November 24, 1998

Mr. Robert Perciasepe
Assistant Administrator
Office of Air and Radiation (6101)
Environmental Protection Agency
401 M Street, SW
Washington, D.C. 20460

Dear Mr. Perciasepe:

On September 16 - 17, 1998, the Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee (a.k.a. ICCR Coordinating Committee) met to discuss recommendations, works-in-progress, and data/information to forward to the Environmental Protection Agency (EPA) for consideration regarding the development of regulations under Sections 112 and 129 of the Clean Air Act. The Committee reached closure on several recommendations and is forwarding the attached documents, which contain these recommendations, to the EPA.

In forwarding works-in-progress to EPA for consideration, the Committee would like to clearly state that these works-in-progress are <u>not</u> forwarded as recommendations. These works-in-progress include draft and incomplete items on which the Committee has <u>not</u> reached closure. Statements in these works-in-progress may not represent the opinions of all Committee members. As a result, these works-in-progress should have only as much weight with the EPA as comments the EPA may receive from any individual.

A list is attached identifying the numerous works-in-progress and data/information items, which the Committee is forwarding to EPA. These items are not attached, because many of them are not available in an electronic format; they were presented to the Designated Federal Official at the conclusion of the September meeting and have been forwarded to EPA staff and placed in the appropriate dockets for future reference.

Finally, in considering the Committee's recommendations or any of the works-in-progress, the Committee urges the EPA to review and consider the minutes documenting the Committee's discussions of these recommendations and works-in-progress at the September meeting.

The ICCR Coordinating Committee was established by the EPA under the Federal Advisory Committee Act (FACA) in September, 1996. The purpose of the Committee was to develop recommendations for consideration by the EPA in the development of regulations for the following stationary combustion source categories: combustion turbines; internal combustion engines; industrial-commercial-institutional boilers; process heaters; and non-hazardous waste incinerators (excluding municipal waste combustors and medical waste incinerators). Sections 112 and 129 direct the EPA to develop regulations limiting emissions of hazardous air pollutants (and several criteria air pollutants) from these source categories by November, 2000.

The Coordinating Committee met six times in fiscal year 1997 and five times in fiscal year 1998. Notice of all meetings of the Committee was published in advance in the Federal Register and all meetings were open to the public.

The Charter establishing this committee expired in September, 1998. As a result, the September 16 - 17, meeting was the final meeting of the ICCR Coordinating Committee.

Sincerely,

[Signed By]	[Signed By]
Richard F. Anderson, Ph.D. Stakeholder Co-Chair ICCR Coordinating Committee	Fred L. Porter EPA Co-Chair ICCR Coordinating Committee

cc: Sally Shaver - Director, Emission Standards Division
John S. Seitz - Director, Office of Air Quality Planning and Standards

Attachments

Attachment I - Works-In-Progress and Data/Information

Attachment II - Regulatory Alternatives Paper

Attachment III - Preliminary Subcategories and MACT Floor Determination for Gas, Distillate Oil and Residual Oil Fired Boilers

Attachment IV -Hazardous Air Pollutants (HAPS) of Interest for Fossil Fuel Fired Boilers

Attachment V - Cost of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Attachment VI - Interpreting and Using Emissions Databases Containing Non-Detection Values

Attachment VII - Definition of "Rich Burn Engine" for the Reciprocating Internal Combustion Engine (RICE) MACT Standard

Attachment VIII - Assessment of the EPA ICCR Emissions Database for Reciprocating Internal Combustion Engines

Attachment IX - Above the Floor MACT for Digester and Landfill Gas Reciprocating Internal Combustion Engines

ATTACHMENT I

Works-In-Progress

Combustion Turbines
Gas-Fired Combustion Turbine MACT Considerations
Model Turbine and Control Alternative Cost Analyses for Existing and New Sources
Pollution Prevention Considerations
Subcategorization Report
HAPs vs. Criteria Pollutants Report
Preliminary Results from Natural Gas-Fired Combustion Turbine Testing

Reciprocating Internal Combustion Engines
Pollution Prevention for Reciprocating Internal Combustion Engines
Summary of Proposed Definitions for Stationary Internal Combustion Engines
Catalyst Control Cost Information
New Source MACT for Reciprocating Internal Combustion Engines

Boilers
Control Technology Rankings
Economics Task Group Analyses
Subcategories for Boilers Firing Wood, Non-Fossil Materials, and Coal
Model Boilers for Boilers Firing Wood, Fossil, and Non-Fossil Materials
HAPs of Interest for Wood-Fired Boilers and Digester Gas-Fired Boilers
Preliminary MACT Floor Analyses for Wood, Non-Fossil, and Coal Boilers
Analyses of Good Combustion Practices (GCP)
De Minimis Levels for Boilers Subject to Section 129

Process Heaters
Rationale for Determination of MACT for Indirect-Fired Process Heaters
Regulation of Sources Firing Coke Oven Gas Under the ICCR
"Other"-Fired Process Heaters Status Report
ICCR Process Heater Database Analysis Flow Diagram
Process Heater Database Analysis of Controlled Units

General ICCR
CC Guidance to Work Groups on Operator Training/Qualification
CC Guidance to Work Groups on Metrics which Encourage Pollution Prevention
CC Guidance to Work Groups on Pollution Prevention Regulatory Options
Guidance on Good Combustion Practices
Pollution Prevention Subgroup Report on Fuel/Waste Constituent Levels and Fuel/Waste De Minimis Constituent Levels

Data/Information

Combustion Turbines
Gas Turbine HAPs Technology Workshop
Refined Inventory Database
Emission Test Database v3.0

ATTACHMENT I (Continued)

Data/Information

Reciprocating Internal Combustion Engines

Emission Test Database v2.0
Inventory/Population Database
Federal Units Population Estimates

Boilers

Summary of State Regulations for Boilers
Literature Search by Emissions Testing Task Group
Materials Analysis not yet Incorporated into Materials Analysis Database v1.0
Refined Inventory Database
Emission Test Database v3.0
Supplements to Boilers Emission Test Database, v4.1 and v4.2

Process Heaters

Refined Inventory Database
Emission Test Database v3.0

Incinerators

Operating Non-Hazardous Solid Waste Incinerators
Subteam #1 Wrap-Up Report
Subteam #2 Development of the ICCR Miscellaneous Industrial and Commercial Incinerator Subcategory List
Subteam #3 Procedure/Documentation
Development of the IWG Subteam #4 database
Environmental Threats to Children, Memorandum
Environmental Threats to Children, Response Letter
Emission Test Database v3.0 - Incinerators and Flares
Supplements to Incinerators Emission Test Database, v4.1 and v4.2

Testing and Monitoring Protocol

A Review of Formaldehyde Measurements by the DNPH Methods
Discussion of Real Time Measurement Options to IC Engine SWG
Typical Products of Incomplete Combustion (PICs) from industrial combustion sources that are also Hazardous Air Pollutants (HAP's)
Review of Compliance Test Methods for Determining Formaldehyde Emissions from IC Engines and Turbines with Potential Application to Other Combustion Sources

General ICCR

Survey Database v2.0
Chlorinated Dioxin and Furan Formation, Control and Monitoring
Inventory Database Version 3.0 and Associated Documentation Tables
Additional Inventory Data from DoD
Additional Inventory and Survey Data from AMSA
Materials Analysis Database v1.0
CC and Subgroup Meeting Minutes
WG and Subgroup Meeting Minutes
Information Collection Plan and Survey Recommendations from CC to EPA (see minutes of March 1997 CC meeting)

ATTACHMENT II

REGULATORY ALTERNATIVES PAPER

Industrial Combustion Coordinated Rulemaking
Federal Advisory Committee

September 16, 1998

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FIGURES AND TABLES

REGULATORY ALTERNATIVES PAPER (RAP)

1.0 INTRODUCTION

The ICCR Coordinating Committee forwards this RAP as recommendations to EPA for consideration in preparing a summary of regulatory alternatives, which the Agency must submit to litigants pursuant to a consent decree involving industrial and commercial waste incinerators. EPA's summary of regulatory alternatives is due to the litigants on November 16, 1998.

The RAP is an intermediate product in the regulatory development process. It contains recommendations regarding categories of *nonhazardous solid waste incinerators* considered for regulation under section 129 of the *Clean Air Act*, the pollutants to be regulated, and potential control alternatives for each incinerator subcategory. Additionally, the RAP contains other relevant subcategory-specific information such as subcategory population statistics, combustion device descriptions, the status of data collection and analysis, and issues and needs. The information and recommendations presented in the RAP are preliminary and will continue to evolve throughout the regulatory development process.

This paper is organized into sections on background, applicability, subcategory characterizations and regulatory alternatives, pollution prevention, statutes and executive orders, and issues and needs. Additionally, draft applicability language and definition sheets for the emission source subcategories identified to date are attached.[1]

2.0 BACKGROUND

In developing recommendations to EPA regarding the development of nonhazardous solid waste incineration regulations under Section 129 of the *Clean Air Act*, the ICCR Coordinating Committee has been following an overall strategy that is illustrated in Figure 1. Beginning with a well defined focus, schedule, and approach, the Committee analyzed the ICCR databases, developed scoping recommendations for new and existing combustion units within an overall regulatory framework, identified emission source subcategories, and prepared floor and control option recommendations.

Four general subcategories have been identified at this point and are listed in Table 1. Because EPA has indicated that boilers and process heaters that combust nonhazardous solid waste should be considered "solid waste incineration units" under Section 129, preliminary placeholder subcategories have been added to this list. However, the number and description of subcategories that may ultimately be addressed under Section 129 remains uncertain at this time, in part because the Agency has yet to adopt a definition of nonhazardous solid waste for use in

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[1]Depending on the final definition of solid waste, it is possible that some process heaters could be subject to Section 129. However, because the applicability of Section 129 to process heaters is still unclear and because only a few such units could ultimately fall under Section 129, process heaters are not covered in this document.

Section 129 regulations.[2] This definition of nonhazardous solid waste is crucial to determining whether certain combustion units will ultimately be considered nonhazardous solid waste incineration units subject to Section 129 or combustion units subject to Section 112. It should be noted that incinerators, boilers, and process heaters have distinctively different functions. Whereas the primary purpose of an incinerator is to reduce the volume of waste, the primary purpose of a boiler is to produce useful steam or hot water, and process heaters are designed to transfer useful heat to an industrial or commercial process.

The ICCR Coordinating Committee recommends the following five nonhazardous solid waste incineration subcategories for possible regulation under Section 129:

- **Miscellaneous Industrial and Commercial Waste Incinerators**
- **Wood and wood waste incinerators** -- *including separate groupings for milled solid and engineered wood; harvested wood and agricultural waste; and construction, demolition, and treated wood wastes.*
- **Pathological waste incinerators and crematories** -- *including separate groupings based on feed rate for poultry farms; human crematories; and hospital, animal control, and research facilities.*
- **Drum reclaimer furnaces**
- **Parts reclaimer burnoff units**

Additionally the ICCR Coordinating Committee has identified the following placeholder subcategories, subject to further analysis and a final definition of nonhazardous solid waste:

- **Potential Section 129 solid mixed feed boilers**
- **Potential Section 129 liquid mixed feed boilers**

Section 129 addresses four categories of incineration units -- municipal solid waste (MSW) combustors, hospital and medical infectious waste (HMIW) incinerators, industrial and commercial waste incinerators (ICWI), and other solid waste incinerators (OSWI). Rules addressing the first two categories have been promulgated. However, rule applicability excludes units combusting less than 30% municipal solid waste, and units burning less than 10% hospital and medical infectious wastes. The <30% municipal solid waste and <10% hospital and medical infectious waste incineration units will be addressed in one of the subcategories ultimately established for the Section 129 rulemaking.

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[2] On June 5, 1998, EPA staff issued a draft definition of nonhazardous solid waste, for purposes of discussion.

The ICCR Coordinating Committee recommends a separate set of regulatory requirements (e.g., emission limits) for each of the above subcategories and groupings. However, EPA may want to consider a further subdividing or combining of these subcategories and groupings as additional information is received and analyzed. Additionally, as new information is received, it may be necessary to create a *miscellaneous* or *other* category to ensure that any units not covered by the above subcategories are addressed.

EPA has indicated that Section 129 addresses incinerator units and other combustor units burning nonhazardous solid waste. The currently identified subcategories are believed to provide comprehensive coverage, with the Miscellaneous Industrial and Commercial Waste Incineration category believed to include the mixed feed and industrial solid waste incineration units not included in any of the other subcategories. However, should that not prove to be the case, the Miscellaneous Industrial and Commercial Waste Incineration category could be expanded to include units not covered, or a new miscellaneous category could be defined. To date, all incinerators in the ICCR's databases that have been assigned to one of the subcategories. Thus, it is unclear whether an additional *miscellaneous* or *other* category will ultimately be necessary.

The ICCR Coordinating Committee recommends that the regulatory requirements for the above nonhazardous solid waste incineration subcategories be addressed in a single rulemaking package (i.e., a single preamble and regulation for proposal, and the same for promulgation) for efficiency purposes and because many of the requirements (e.g., for monitoring, recordkeeping, reporting, operator training and certification, siting, and pollution prevention) may be the same across multiple subcategories. This approach will simplify the rulemaking process, thereby fostering understanding of the regulatory requirements and better compliance. Because Section 129 distinguishes between ICWI and OSWI, EPA has indicated that the rulemaking package would need to distinguish between these two categories of combustion units. Although the November 16, 1998, consent decree only requires EPA to discuss regulatory alternatives for ICWI sources, OSWI sources are also discussed in this RAP due to their similarity and because of the above recommendation that EPA develop a combined ICWI/OSWI regulation.

Much of the work to date has been devoted to analyzing data contained in the following three databases:

- **Inventory database** -- *a detailed listing of industrial and commercial combustion units derived from existing State and federal databases by EPA.*

- **Information collection request (ICR)/survey database** -- *responses from an EPA information collection request (ICR) providing updated and detailed information for facilities identified in the inventory database as combusting nonhazardous solid waste.*

- **Emissions database** -- *emissions data collected from State agencies by EPA representing source testing of a variety of combustion units.*

The ICCR inventory database contains 8,091 facilities believed to have one or more incineration units. However, the responses to the ICR indicate that many of these units have been shut down or otherwise do not exist. (This may reflect the substantial progress made by industry in recent years to reduce the amount of waste produced.) Other units were eliminated from consideration because they were determined to be burning hospital and infectious medical waste, municipal waste, or other types of materials covered by other EPA regulations (e.g., hazardous waste). The status of about 1,700 potential units remains unknown because of insufficient information. Taking all of these factors into consideration, the best estimate of the number of incineration units in the inventory and ICR databases that are currently in operation is about 1,600. This estimate could increase or decrease by several hundred units as more information becomes available.

The extent to which the inventory and ICR databases capture all operating incinerators in the U.S. is unknown. However, based on population estimates for individual subcategories, a rough guess is that the inventory and ICR databases represent most of the wood, wood waste, and drum and parts reclaimer units currently operating in the U.S. and over 50% of the remaining incineration subcategories, with the exception of several thousand poultry farm incinerators. These poultry farm units, typically rated at <100 lb/hr, have probably never been regulated or permitted due to their small size. In summary, although not all incineration units are captured within the databases, the ICCR Coordinating Committee recommends that the databases be considered by EPA as representative of the cross-section of U.S. incinerators and provide a basis for rulemaking.

3.0 APPLICABILITY

The recommendations presented in this RAP will apply to all incineration units that are not exempt from Section 129 or addressed by other rulemakings. Section 129(g)(l) exempts wastes required to have a permit under Section 3005 of the Solid Waste Disposal Act (i.e., hazardous wastes), material recovery facilities which combust waste for the primary purpose of recovering metals, qualifying small power production and co-generation facilities, and air curtain incinerators combusting only yard and wood wastes and clean lumber. Additionally, municipal waste combustors and hospital and medical infectious waste incinerators are exempt from this rulemaking because they are being addressed by EPA in parallel rulemakings or because they are already covered by other rulemakings. An example of draft applicability language and definitions for a combined ICWI/OSWI rule are presented in Attachment A.

4.0 SUBCATEGORY CHARACTERIZATIONS AND REGULATORY ALTERNATIVES

Descriptions of each recommended subcategory are presented in Attachment B and summarized in Table 2. Additionally, information and recommendations are presented on pollutants considered for regulation (at a minimum the nine pollutants listed in Section 129), whether a subcategory falls under ICWI or OSWI, any groupings within the subcategory, population statistics, material combusted, combustion device description, the basis for subcategory bounds, the floor level of control, the status of data collection and analysis, issues and needs, and other comments.

Based on the information currently available, it appears that most existing incineration units have minimal or no controls in place. The exception is for most drum reclaimer furnaces and parts reclaimer burnoff ovens, which appear to have thermal oxidizers. Only very limited test data on most pollutants of interest are available for all incinerator subcategories, and the ICCR Coordinating Committee has recommended test programs to address these data needs. Some subcategories (e.g., wood wastes) are small in terms of the number of operating units, and these may be candidates for merging into a larger subcategory, provided that unit designs, emissions, and controls are similar. For the two preliminary subcategories, several floor controls and options above the floor have been identified.

5.0 POLLUTION PREVENTION

The ICCR Coordinating Committee recommends that pollution prevention should be considered an integral part of the Section 129 rulemaking and is committed to a further investigation of the feasibility, practicality, and cost-effectiveness of various pollution prevention techniques. This commitment is consistent with the goals of the *Pollution Prevention Act of 1990* and EPA policy to consider and facilitate the adoption of source reduction techniques. Additionally, EPA has stated its opinion that Section 129(a)(3) of the *Clean Air Act* anticipates that pollution prevention may be included in regulations (i.e., as the basis of a floor or control level above the floor) by stating that standards "... shall be based on methods and technologies for the *removal* or destruction of pollutants *before*, during, or after combustion ... [emphasis added]." Thus, pollution prevention allows sources, in meeting numeric emissions limits, to choose pollution prevention measures as alternatives to add-on pollution control devices.

Discussed below are several specific pollution prevention approaches forwarded to EPA for consideration.

<u>Good combustion practices</u>. Good combustion techniques include:

- Operator practices
- Maintenance knowledge and practices
- Stoichiometric ratio (air/fuel)
- Firebox residence time, temperature, and turbulence
- Fuel/waste quality, handling, sizing, dispersion, and liquid atomization
- Combustion air distribution

If appropriate, implementation of these techniques could be accomplished through a combination of documented operating and maintenance procedures, logs and record-keeping, training on equipment and procedures, routinely scheduled inspections and maintenance, burner and control adjustments, system design, fuel/waste monitoring, and various system adjustments. (Although operator training itself could also be considered a good combustion practice, it is covered separately below.) These techniques are potentially applicable to incineration units under Section 129, but the specific applicability, benefit, disbenefit, or cost effectiveness of these techniques has not been assessed by the Committee.

Practical and effective combustion practices may be applicable to some of the subcategories. Because of the variety of unit designs and waste types being addressed, it may be appropriate to develop a separate set of GCPs for each subcategory. For some subcategories, no GCPs may be appropriate. On the other hand, if there are practical and effective combustion practices that are the same or similar among multiple subcategories, a single set of GCPs for all units covered by those subcategories may be appropriate.

Operator Training/Qualification. Section 129(d) requires EPA to "... develop and promote a model State program for the training and certification of solid waste incineration unit operators ..." The ICCR Coordinating Committee recommends the following definition of "operator:"

- Operator means an individual or individuals whose work duties include the operation, evaluation, and/or adjustment of the combustion system.

Additional specificity will be needed, however, to distinguish unit "operators" from mechanics, engineers, and others who may occasionally evaluate or adjust the combustion system. A clear distinction will have to be made between the incinerator "operator" and the "owner/operator" of the unit or facility.

An initial list of potential pollution prevention approaches for consideration includes specific training program elements, including:

- Training and qualification criteria
- Training programs and qualification exams
- Training program materials and documentation of qualification

The ICCR Coordinating Committee recommends these requirements for some incinerator operators, although details will need to be worked out. In addition, the Committee also recommends that each facility develop an operator training and testing program tailored to their equipment and site.

Metrics. Emission limits previously promulgated under Section 129 (i.e., the municipal waste and hospital and medical infectious waste rules) have been expressed in units of concentration (e.g., *ng/dscm* or *ppm*). Concentration units are effective in reducing emissions based on control device efficiency and may also encourage pollution prevention. However, some pollution prevention techniques that significantly reduce mass emission rates may not concurrently reduce mass concentrations.

To encourage pollution prevention, the ICCR Coordinating Committee recommends consideration of metrics other than concentration emission limits, where the numerator in the emission limit would be based on pollutant mass (e.g., *ng*) and the denominator would be based on time, energy output, heat input, fuel/waste input, or unit of production. However, compliance with such metrics may be impractical where the metrics are combustion unit size/capacity specific (e.g., metrics based on time), difficult to measure (e.g., metrics based on energy output, heat input, or fuel/waste input), or difficult to quantify (e.g., metrics based on unit of production). The

Committee recommends consideration of the concept of metrics, but also recommends additional study to determine whether this approach is practical or appropriate for compliance and effective in reducing emissions from Section 129 incineration units.

Regulatory Options. The ICCR Coordinating Committee recommends that EPA consider regulatory options such as waste accounting and recordkeeping and work practice standards. Waste accounting and recordkeeping would provide a paper trail of waste feedstream composition, thereby highlighting opportunities for source separation, source elimination, or recycle/recovery. Work practice standards would require specific handling or separation procedures for waste materials prior to burning, thereby reducing undesirable materials (e.g., waste components leading to specific HAP emissions) and potentially improving combustion efficiency (e.g., by removing high moisture content materials from the waste steam).

While the Committee recommends consideration of these techniques in principle, further information is needed on: (1) what specific handling or separation procedures might be applied to each of the subcategories, (2) the data or reasoning (e.g., based on combustion chemistry or engineering calculations) leading to the conclusion that a specific handling or separation procedure would provide a significant net life-cycle environmental benefit, and (3) evaluation of the potential benefit versus the burden (including economic burden) imposed.

6.0 STATUTES AND EXECUTIVE ORDERS

In addition to the substantive requirements imposed by the Clean Air Act when promulgating regulations, EPA must comply with a number of administrative responsibilities prior to adopting regulations. Some of these obligations flow from statutes and others from executive orders (EOs) signed by the President as directives to the Executive Branch.

EPA must comply with administrative requirements in the following five statutes at the proposal stage of a regulation's development.[3]

- Section 307(d) of the *Clean Air Act* requires that regulations under Section 129 be supported by a rulemaking docket and allow for both written and oral comment upon the proposed rule.

- Under the *Paperwork Reduction Act*, EPA must obtain a control number from the Office of Management and Budget (OMB) if the regulation contains any information collection request (reporting obligations under an applicable emission standard, for instance) calling for answers to identical questions posed to ten or more persons.

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[3]One additional statutory administrative requirement is triggered when the Agency promulgates *final* regulations. Under the Congressional Review Act, EPA generally must submit all rules of general applicability to Congress and the Comptroller General before the rule may take effect.

- The *National Technology Transfer and Advancement Act (NTTAA)* mandates that EPA must use existing suitable voluntary consensus standards (e.g., test methods) unless their use would be inconsistent with applicable law or otherwise impractical in EPA's judgment.

- If the proposed regulation will contain a federal mandate forcing State, local, and tribal governments, in the aggregate, or the private sector to spend in excess of $100 million in any given year, the *Unfunded Mandates Reform Act (UMRA)* requires EPA to prepare a statement identifying a number of economic and environmental costs and benefits associated with the proposed rule, both locally and nationally. UMRA also requires that, for proposed rules which require an UMRA statement, EPA must identify and consider a reasonable number of regulatory alternatives and select the least costly, most cost-effective, or least burdensome option that is consistent with the agency's statutory duties, unless EPA explains its choice not to select one of the foregoing options. UMRA lastly contains two consultation requirements: (1) EPA must develop an effective process for consulting with elected officers of State, local, and tribal governments with regard to proposed rules that contain significant Federal intergovernmental mandates, and (2) it must develop a small government agency plan (which provides for notice to, input from, and education for, small governments regarding a proposed rule) for any rule that might significantly or uniquely affect small governments.

- The *Regulatory Flexibility Act (RFA)*, as amended by the Small Business Regulatory Enforcement Fairness Act, requires EPA to prepare an initial regulatory flexibility analysis (IRFA), convene a small business advocacy review panel, and include the IRFA or a summary of it in the proposal's preamble, unless the Administrator can certify that a proposed regulation will not have a significant economic impact on a substantial number of small entities. (Additionally, Section 507 of the Act requires EPA and the States to develop small business stationary source technical and environmental compliance assistance programs.)

In addition to its statutory obligations, EPA has the following four EOs to consider.

- Under *EO 12875, Enhancing the Intergovernmental Partnership*, EPA must develop an effective process for elected officials and other representatives of State, local, and tribal governments to provide meaningful and timely input on regulatory proposals containing significant unfunded mandates. Also, EPA may not (unless required by law) promulgate a regulation that creates an unfunded mandate upon State, local, or tribal governments without either providing funds necessary to pay the direct costs of compliance, or providing OMB a description of EPA's consultation with representatives of affected governments, the nature of their concerns, and EPA's position supporting the need for the regulation. (Congress subsequently enacted similar requirements in UMRA.) In some instances, EPA can waive regulatory requirements.

- Under *EO 13084, Consultation and Coordination with Indian Tribal Governments*, EPA must establish an effective process permitting elected officials and other representatives of Tribal governments to provide meaningful and timely input into the development of regulatory policies for matters significantly or uniquely affecting their communities. In certain instances, the federal government must either fund compliance costs, or EPA must provide OMB a description of the extent of EPA's consultation with representatives of affected Tribal governments, the nature of their concerns, and EPA's position supporting the need for the regulation. In some instances, EPA can waive regulatory requirements. (These requirements are very similar to those in *EO 12875*.)

- Prior to proposal, *EO 12866* requires that EPA seek involvement of parties affected by a proposed rule and suggests that at least a 60 day comment period on proposed rules be offered. The same EO also requires that EPA submit to OMB any proposed or final *significant* regulatory action for interagency review.[4]

- *E.O. 12898* specifies that EPA must make achieving environmental justice part of its mission by identifying and addressing, as appropriate, practicable, and permitted by law, disproportionately high and adverse human health or environmental effects of its rulemaking actions on minority and low-income populations.[5]

The ICCR has laid the groundwork for developing recommendations aiding EPA's compliance with these obligations. Specifically, the use of *model plants*, which reflect the design of typical facilities in the affected industry could be used when EPA seeks to conduct the economic and environmental analyses necessary to comply with UMRA, RFA, and *EO 12866*. The Agency could consider the effect of proposed regulations upon these model plants as illustrative of the impact the proposals may have nationally. In addition, in the course of recommending hazardous air pollutants (HAPs) for testing and regulation under Section 112, the

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[4]*Significant* is defined as an action having an annual effect on the economy of $100 million or more; adversely affecting in any material way the economy, a sector of the economy, jobs, the environment, public health or safety, or affected governments or communities; creating a serious inconsistency or interfering with an action taken or planned by another agency; materially altering the budgetary impact of entitlements, grants, etc., or the rights/obligations of recipients; or raising novel legal or policy issues.

[5]If a rule is *significant* under *E.O. 12866* and it involves an environmental health or safety risk that EPA has reason to believe may disproportionately affect children, *EO 13045* requires EPA to evaluate the environmental health or safety effects of the planned regulation on children and explain why the proposal is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. Since the standards to be developed under Section 129 are technology-based and not health- or risk-based, *EO 13045* does not apply to the determination of MACT floor. The ICCR Coordinating Committee recommends that EPA consider whether and how *EO 13045* would influence MACT standard regulatory development (e.g., the selection of pollutants in addition to those listed in section 129(a)(4)).

Committee has also identified existing test methods for measuring HAPs, and recommendations that these existing test methods be considered for determining compliance with regulations could be useful to the Agency's compliance with the NTTAA's requirement to search for applicable voluntary consensus standards. Next, Section 129(a)(3) directs that standards for new sources incorporate "siting requirements that minimize, on a site specific basis, to the maximum extent practicable, potential risks to public health and the environment." Siting requirements may trigger environmental justice concerns.

7.0 ISSUES AND NEEDS

Waste Burning Boilers. Incinerators burning non-hazardous solid waste are covered under Section 129. However, there is an unresolved issue concerning boilers that burn waste or waste mixed with fuels (e.g. coal or natural gas). EPA's current opinion is that a boiler burning nonhazardous solid waste, as ultimately defined by EPA, is covered by Section 129. (See *footnote 2* regarding the status of the definition of nonhazardous solid waste.) Does this mean if the boiler burns any amount of waste that it is covered, or is there a minimum amount necessary before it falls under Section 129? In the case of incinerators that burn municipal solid waste (MSW), the unit falls under Section 129 if more than 30% MSW is combusted. However, in the case of boilers, the issue may be more complex since the composition and amount of waste burned may vary with time, and the toxicity of the emissions will also vary depending upon the composition of the waste stream. Since at present EPA has not finalized its definition of nonhazardous solid waste for the purposes of Section 129, should all materials disposed of by burning be addressed under Section 129?

Waste Composition Averaging Time. In many cases, incinerators and boilers burn waste streams that are not homogeneous. Depending upon the facility and wastes disposed of, waste "A" may be burned for several hours early in the work day, followed by waste "B," followed by wastes "C" and "D" or a mixture of A, B, C, and D in varying amounts. In some cases, waste "E" will be burned for several months, followed by waste "F" for some period of time. This may result in widely varying emissions over the course of a day, month, or year. Unless emissions testing is done when each waste is burned and in all possible combinations, emissions data will not be representative of actual operating conditions. Operating permits often specify a waste composition to be burned (e.g., % waste "X" per unit time), and long averaging times may result in periods of emissions of widely varying toxicities while still conforming to the conditions of the permit. Based on the above operating scenarios, an analysis of waste composition over time and resulting emissions is needed to define an acceptable averaging time for each subcategory. This analysis is necessary for purposes of determining the applicability of the standards, setting the level of the standards, and determining compliance. The heart of the issue is how averaging time impacts toxicity of emissions by allowing variability of mass emission rates while still assuring the protection of human health.

TABLE 1. INCINERATOR SUBCATEGORIES

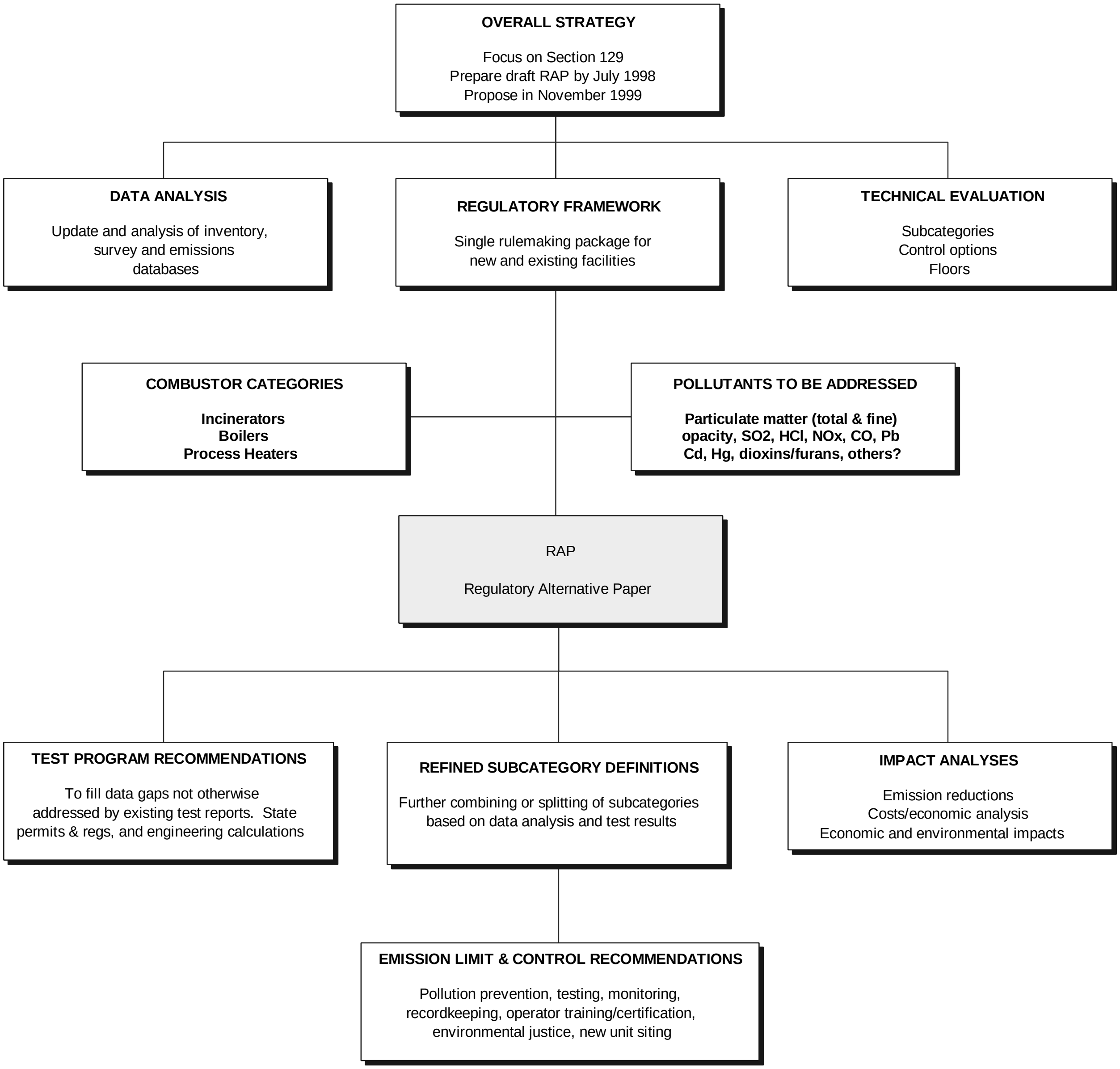

Figure 1. Illustration of steps leading to the RAP and beyond.

SUBCATEGORY	SUBCATEGORY SCOPE
Pathological Wastes and Crematories	▸ *Pathological wastes and crematories, including these groupings:* *a. Poultry farms ... (<100 lb/hr)* *b. Human crematories ... (100-500 lb/hr)* *c. Hospital, animal control, research facilities ... (>500 lb/hr)*
Chemical, Petroleum, and Pharmaceutical Solids, Liquids, and Sludges	▸ *Miscellaneous Industrial and Commercial Waste Incinerators*
Wood, Construction & Demolition, and Agricultural Wastes	▸ *Wood, construction & demolition, and agricultural wastes, including these groupings:* *a. Milled solid and engineered wood* *b. Harvested wood and agricultural* *c. Construction, demolition, and treated wood*
Metal Parts and Drums	▸ *Drum reclaimer furnaces* ▸ *Parts reclaimer burnoff units*

TABLE 2. SUBCATEGORY DEFINITIONS

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
<u>Miscellaneous Industrial and Commercial Waste Incinerators</u>	None identified at this time	By-products of industrial operations (including combinations with less that 30% municipal-type solid waste or less than 10% medical waste), environmental control device sludges, waste by-products, maintenance residues, off-test and out-dated materials, and packaging materials	ICWI	203		Section 129 pollutants	Undetermined: 12% of the units surveyed report controls for one or more of the following pollutants: PM, NOx, SOx, HCl, and CO	
<u>Wood and Wood Wastes</u>	Milled Solid and Engineered Wood Wastes	Wastes and residues resulting from wood-working manufacturing activities, containing 2 to 15 percent by weight adhesives, glues, and binders in engineered woods, and containing no more than 5 percent by weight of contaminants such as cardboard, paper, paints, and solvents	OSWI	18		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors

TABLE 2. SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
“	Harvested Wood and Agricultural Wastes	Wastes and residues resulting from land clearing, orchard, silviculture, nursery, green-house, agricultural, and forest management activities and sawmill operations and con-training no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper	OSWI	8		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors
“	Construction, Demolition, and Treated Wood Wastes	Wastes and residues resulting from: (1) the construction, remodeling, repairing, and demolition of individual residences, commercial buildings, and other structures, and (2) the treatment of wood products that are impregnated or otherwise treated with various preservatives for the purpose of protecting or other-wise extending the structural properties of the wood	OSWI	9		Section 129 pollutants	No control	Considering good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors

TABLE 2. SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
Pathological Waste Incinerators and Crematories	<100 lb/hr (primarily poultry farmers; also small animal crematories, veterinary centers, humane societies, and pharma-ceutical companies)	Human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding (if applicable)	OSWI		Potentially several thousand	Section 129 pollutants	None	See Attachment B: "Potential Incinerator Control Options" (page B-17) and "ICCR Coordinating Committee Recommendations for Pollution Prevention Options" (page B-20)
"	100 to 500 lb/hr (primarily human crematories; also animal crematories, veterinary clinics, humane societies, and pharma-ceutical companies)	"	OSWI		2,000	Section 129 pollutants	None	See Attachment B: "Potential Incinerator Control Options" (page B-17) and "ICCR Coordinating Committee Recommendations for Pollution Prevention Options" (page B-20)

TABLE 2. SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
"	>500 lb/hr (primarily animal disposal systems for hospitals, animal control facilities, and research facilities)	"	OSWI		100	Section 129 pollutants	None	See Attachment B: "Potential Incinerator Control Options" (page B-17) and "ICCR Coordinating Committee Recommendations for Pollution Prevention Options" (page B-20)
Drum Reclaimer Furnaces	None	An incinerator used to reclaim steel containers (e.g., 55 gallon drums) for re-use or to prepare them for recycling by burning or pyrolyzing interior and exterior container coatings and residues prior to cleaning by abrasive shot blasting (containers must be empty as defined by RCRA prior to processing)	ICWI	44	55	To include Section 129 list	Thermal oxidation for existing and new units	Spray dryer or wet scrubber for acid gases; fabric filter for metals; GCPs

TABLE 2. SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
<u>Parts Reclaimer Burnoff Units</u>	None	An incinerator used to reclaim metal parts such as paint hooks and racks, electric motor armatures, transformer winding cores, and electroplating racks for use in their current form by burning off cured paint, plastisol (i.e., polyvinyl chloride and phthalate plasticizer), varnish, or unwanted parts such as plastic spacers or rubber grommets	ICWI	332	~1350	Section 129 pollutants	Thermal oxidizers for existing and new units	Spray dryer or wet scrubber for acid gases; fabric filter for metals; GCPs
<u>Potential Section 129 Solid Mixed Feed Boilers</u>	None	Various non-fossil Section 129 solid materials generally co-fired with other non-fossil materials or fossil fuels	TBD	322		Section 129 pollutants	<u>Preliminary</u>: fabric filters for metals, scrubbers for inorganic HAPs, and GCPs for organic HAPs; scrubbers for Hg from new units	<u>Preliminary</u>: carbon adsorption for organic HAPs and Hg; none identified for metals and inorganic HAPs

TABLE 2. SUBCATEGORY DEFINITIONS (Continued)

SUB-CATEGORY NAME	GROUPING WITHIN SUB-CATEGORY	MATERIAL COMBUSTED	ICWI or OSWI	EST. NO. OF UNITS		POLLUTANTS CONSIDERED FOR REGULATION	FLOOR LEVEL OF CONTROL	REGULATORY ALTERNATIVES ABOVE FLOOR
				IN DATA-BASE	NATION-WIDE			
Potential Section 129 Liquid Mixed Feed Boilers	None	Various non-fossil Section 129 liquid materials generally co-fired with other non-fossil materials or fossil fuels	TBD	153		Section 129 pollutants	Preliminary: Existing units -- ESPs for metals, scrubbers for inorganic HAPs, and GCPs for organic HAPs. New units -- fabric filters for metals, gas absorbers for inorganic HAPs, GCPs for organic HAPs, and scrubbers for Hg	Preliminary: Fabric filters for metals and carbon adsorption for organic HAPs and Hg; none identified for inorganic HAPs

ATTACHMENT A

EXAMPLE APPLICABILITY LANGUAGE AND DEFINITIONS

Subpart [?] -- Standards of Performance for Solid Waste Incineration Units for Which Construction is Commenced After [date]

Section [?] Am I subject to this regulation?

(a) Except as provided in paragraph (b) of this Section, the affected facility to which this subpart applies is each individual Solid Waste Incineration Unit for which construction or reconstruction is commenced after [date] or for which modification is commenced after [date].

(b) The following facilities are not subject to this subpart:

(1) Any incinerator or other unit required to have a permit under Section 3005 of the Solid Waste Disposal Act (subpart EEE).

(2) Any materials recovery facility (including primary or secondary smelters) which combusts waste for the primary purpose of recovering metals.

(3) Any qualifying small power production facility, as defined in Section 3(17)(C) of the Federal Power Act (16 U.S.C. 769(17)(C)), or qualifying cogeneration facilities, as defined in Section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), which burn homogeneous waste (such as units which burn tires or used oil, but not including refuse-derived fuel) for the production of electric energy or, in the case of qualifying cogeneration facilities, which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.

(4) Any air curtain incinerator that burns only wood wastes, yard wastes, and clean lumber and that complies with the opacity limitations in subpart [?].

(5) Any incinerator or other unit which meets the applicability requirements under subpart Cb, Ce, Ea, Eb, or Ec of this part (i.e., standards or guidelines for municipal waste and hospital and medical infectious waste incinerators).

(6) Municipal sewage sludge incinerators which meet the applicability requirements under subpart [?].

Sec. [?] How are the terms used in this subpart defined?

Air Curtain Incinerator means an Incinerator that operates by forcefully projecting a curtain of air across an open chamber or pit in which burning occurs; Incinerators of this type can be constructed above or below ground and with or without refractory walls and floor.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting useful thermal energy in the form of hot water, saturated steam, or superheated steam. The principal components of a boiler are a burner, a firebox, a heat exchanger, and a means of creating and directing gas flow through the unit. A boiler's combustion chamber and primary energy recovery section(s) must be of integral design (i.e., the combustion chamber and the primary energy recovery section(s), such as waterwalls and superheaters, must be physically formed into one manufactured or assembled unit.) (A unit in which the combustion chamber and the primary energy recovery section(s) are joined only by ducts or connections carrying flue gas is not integrally designed; however, secondary energy recovery equipment (such as economizers or air preheaters) need not be physically formed into the same unit as the combustion chamber and the primary energy recovery section.) Only stand alone boilers are covered by this definition; waste heat boilers which are associated with stationary gas turbines or engines are excluded.

Commercial and Industrial Solid Waste Incineration Units means the following types of Solid Waste Incineration Units: Miscellaneous Industrial and Commercial Waste Incinerators; Drum Reclaimer Furnaces; Parts Reclaimer Burnoff Units; and potentially other applicable subcategories of boilers and process heaters].

Construction, Demolition, and Treated Wood Waste Incinerator means an Incinerator, Liquid Mixed Feed or Solid Mixed Feed Boiler, or Process Heater combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from: (1) the construction, remodeling, repairing, and demolition of individual residences, commercial buildings, and other structures, including pallets; forming and framing lumber; treated lumber; shingles; tar-based products; plastics; plaster; wallboard; insulation material; broken glass; painted or contaminated lumber; chemically treated lumber; white goods; reinforcing steel; and plumbing, heating, and electrical parts; and (2) the treatment of wood products that are impregnated or otherwise treated with various preservatives (e.g., creosote, copper compounds, arsenic compounds, pentachlorophenol, [to be added]) for the purpose of protecting or otherwise extending the structural properties of the wood.

Drum Reclaimer Furnace means an incinerator used to reclaim steel containers (e.g., 55 gallon drums) for reuse or to prepare them for recycling by burning or pyrolyzing interior and exterior container coatings and residues prior to cleaning by abrasive shot blasting. (Containers must be empty as defined by RCRA prior to processing.)

Harvested Wood and Agricultural Waste Incinerator means an Incinerator, Liquid Mixed Feed or Solid Mixed Feed Boiler, or Process Heater combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from land clearing, orchard, silviculture, nursery, greenhouse, agricultural, and forest management activities and sawmill operations and containing no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper.

Incinerator means any enclosed device using controlled flame combustion to combust Solid Waste for the primary purpose of reducing the volume of waste and does not incorporate heat recovery as part of its integral design.

Liquid Mixed Feed Boiler means a Boiler combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of various non-fossil liquid materials which are generally co-fired with other non-fossil materials or fossil fuels.

Milled Solid and Engineered Wood Waste Incinerator means an Incinerator, Liquid Mixed Feed or Solid Mixed Feed Boiler, or Process Heater combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of wastes and residues resulting from woodworking manufacturing activities, containing 2 to 15 percent by weight adhesives, glues, and binders in engineered woods, and containing no more than 5 percent by weight of contaminants such as cardboard, paper, paints, and solvents.

Miscellaneous Industrial and Commercial Waste Incinerator means an Incinerator, Liquid Mixed Feed or Solid Mixed Feed Boiler, or Process Heater combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on an annual basis, of byproducts of industrial operations (including combinations with less that 30% trash or less than 10% medical waste), environmental control device sludges, waste byproducts, maintenance residues, off-test and out-dated materials, and packaging materials.

Other Solid Waste Incineration Unit means the following types of Solid Waste Incineration Units: Construction, Demolition, and Treated Wood Waste Incinerators; Harvested Wood and Agricultural Waste Incinerators; Milled Solid and Engineered Wood Waste Incinerators; Pathological Waste Incinerators and Crematories; and potentially other applicable subcategories of boilers and process heaters].

Parts Reclaimer Burnoff Unit means an Incinerator used to reclaim metal parts such as paint hooks and racks, electric motor armatures, transformer winding cores, and electroplating racks for use in their current form by burning off cured paint, plastisol (i.e., polyvinyl chloride and phthalate plasticizer), varnish, or unwanted parts such as plastic spacers or rubber grommets.

Pathological Waste Incinerator and Crematory Unit means an Incinerator combusting Solid Waste comprised, in aggregate, of more than 90 percent by weight, as measured on a daily basis (and more than 70 percent on an individual batch basis), of only human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding (if applicable).

Process Heater means an enclosed device using a controlled flame with physical provisions for recovery and exporting thermal energy to an industrial or commercial process or process stream, principally in a form other than hot water, saturated steam, or superheated steam.

Solid Mixed Feed Boiler means a Boiler combusting Solid Waste comprised, in aggregate, of more than [number] percent by weight, as measured on a [time period] basis, of various non-fossil solid materials which are generally co-fired with other non-fossil materials or fossil fuels.

Solid Waste means ... [This definition is currently under discussion at EPA. The definition will apply only to units under Section 129 that combust nonhazardous solid waste.]

Solid Waste Incineration Unit means a distinct operating Incinerator, Boiler, or Process Heater unit of any facility which combusts any Solid Waste material from commercial or industrial establishments or the general public (including single and multiple residences, hotels, and motels), including Commercial and Industrial Solid Waste Incineration Units and Other Solid Waste Incineration Units, but excluding the facilities identified in section (b).

ATTACHMENT B

DRAFT SUBCATEGORY DEFINITION SHEETS

SUBCATEGORY NAME: Miscellaneous Industrial and Commercial Waste Incinerators

ASSIGNED CAA Section (ICWI OR OSWI): Section 129 (ICWI)

GROUPINGS WITHIN SUBCATEGORY:

This subcategory includes incinerators operated by industry in the twenty three (23) SIC groupings including the following: 13, 20, 22, 23, 24, 26, 28, 29, 30, 33, 34, 35,36, 37, 42, 46, 49, 51, 55, 73, 75, 87, 92, 97. These include the following industries:

Aircraft
Catalyst manufacturing
Government/municipality
Industrial organic and inorganic chemicals
Metal products
Oil and gas
Petrochemical
Photo processing
Pharmaceutical
Tire and rubber

Incinerators in this subcategory are located in 29 states as follows:

Arkansas (4), Alabama (2), California (21), Connecticut (9), Georgia (2), Iowa (6), Idaho (1), Illinois (3), Indiana (11), Kansas (1), Louisiana (13), Massachusetts (6), Maine (3), Michigan (13), North Carolina (9), North Dakota (2), Nebraska (2), New Jersey (7), Ohio (5), Pennsylvania (15), Puerto Rico (12), South Carolina (8), Tennessee (8), Texas (36), Virginia (9), Washington (6), Wisconsin (5), West Virginia (2).

There is no basis for subcategorization based on industry type or waste type, but the ICCR Coordinating Committee has not evaluated the potential for subcategorization based on size, feed rate, or incinerator type (continuous or batch).

POPULATION STATISTICS:

Nationwide, there are 203 units assigned to this subcategory based on the EPA databases. The number of units in this subcategory will increase as units in the uncharacterized incinerator database are assigned to subcategories. This could cause the database to double but would not necessarily add new characterization data. It should also be noted that the number of units in this subcategory has decreased, based on the results of the EPA ICR, and this may reflect a trend by owners and operators toward the use of commercial waste destruction facilities or alternate waste disposal methods including pollution prevention techniques. As a result, while new plants may be constructed in the future, the general trend will be toward a reduction in the population of this type on incinerator.

The database information has not been characterized based on the size of a particular unit or its throughput capacity. Either of these characterizations could form the basis for further subcategorization of this subcategory. These data may be contained in the ICR/survey database or in the test report information.

This subcategory is also characterized by units that are operated as either batch or continuous units. The type of operation can form the basis for further subcategorization An analysis of the impact of the type of operation (i.e. batch vs. continuous) on subcategorization has not been done.

MATERIAL COMBUSTED:

Byproducts of industrial operations, including combinations with less that 30% trash or less than 10% medical waste, environmental control device sludges, industrial process biosolids, waste byproducts, maintenance residues, off-test and out-dated materials, and packaging materials.

Based on inventory data, waste descriptions include:

> Aqueous waste, commercial and industrial wastes, decorative laminate/cast polymer scrap, industrial sludge, industrial wastewater sludge, liquid wastes, medical waste (less than 10 percent of total feed), municipal solid waste (below 30 percent of feed), plastics, waste oil, pathological wastes, finishing wastes and paint wastes.

Attached is a list, extracted from the database, of the wastes that are destroyed in the subcategory's units. As can be seen from the list, no particular waste predominates. This subcategory cannot support groupings based on the material burned.

COMBUSTION DEVICE: All types of incinerators are used in this subcategory, including, but not limited to, single and multiple chamber (including multiple hearth), fluid bed, rotary kilns, and tray types. The breakdown of units is as follows:

Multiple Chamber	45.2%
Single Chamber	25.4%
Rotary	9.7%
Fluidized Bed	2.3%
Otherwise classified	1.4%
Unclassified	16.0%

A more detailed list of combustion devices is attached.

Air pollution control devices are generally add-on units whose use is driven by state regulations and permit conditions. The database contains information on controls device on 78 of 203 units. Of these 78 units, 20 had no controls. Of the remaining 58 units, the database indicates that they were equipped with 124 control devices. 45 units have control devices for particulates (58%), 25 units have controls for CO (32%), 17 units have SOx control devices (22%), 20 units have devices for controlling NOx (26%) and 20 of which have control devices for HCl (26%). Many of the 58 units with controls have redundant controls, apparently due to state requirements presumably aimed at ensuring high reliability. Units with multiple control devices which may actually be multiple units are not accurately depicted in the data base but may be easier to identify from original survey sheets. (Note: The representativeness of the above 78 units relative to the total number of units in the database (203) in terms of control device use must be determined.)

<u>PM control equipment</u> listed in the database include wet scrubbers, wet cyclone separators, venturi scrubbers, single cyclones, packed columns, multiple cyclones, mist eliminators, impingement plate scrubbers, ESP, afterburners, chemical neutralization, fabric filters.

<u>CO control equipment</u> listed in the database include air/fuel ratio control, afterburner, and staged combustion.

<u>SOx control equipment</u> listed in the database include venturi scrubbers, sodium alkali scrubbing systems, packed absorption, mist eliminators, impingement plate scrubbers, sorbent injection, chemical neutralization, and alkalized fly ash scrubbers.

<u>NOx control equipment</u> listed in the database include air to fuel ratio control, ammonia injection, chemical neutralization, impingement plate scrubber, low NOx burners, low excess air firing, packed absorption column, staged combustion, and venturi scrubbers.

<u>HCl control equipment</u> listed in the database include wet scrubbers, venturi scrubber, packed column, mist eliminator, sorbent injection, chemical neutralization, and flyash alkaline scrubbing.

A further breakout of the air pollution control devices is attached.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes solids, liquid, and sludge incinerators mostly within SIC code 28, but includes incinerators burning a range or variety of materials at all types of facilities. Of the total number of units in the database, 53.9% were from the 28 SIC grouping. Based on the current analysis of the database, there is insufficient information to determine whether there are statistically significant groupings of emissions over the category, although further analysis might indicate some basis for subcategorization based on the size of the incinerator, the throughput of the incinerator, or the type of operation (batch vs continuous).

POLLUTANTS CONSIDERED FOR REGULATION: Particulate matter (total and fine), opacity (as appropriate), SO_2, HCl, NOx, CO, Pb, Cd, Hg, and dioxins and furans.

FLOOR LEVEL OF CONTROL: Emission data for the individual units has not been reviewed to see if this data is sufficient or able to identify a MACT floor. Although more than 12 percent of the units have some types of controls, there is also a large percentage with no control. Significant numbers of units (i.e. more than 12 percent) reported some type of control for particulates, SO_2, HCl, NOx, or CO. The analysis of the data is incomplete, and it is unknown at this point how many units control multiple pollutants. Control for one or more of these pollutants could identify a MACT floor. However, the actual emission limit associated with PM control has not been established. No control devices have been identified for Pb, Cd, Hg, or dioxins and furans, although it may be assumed that particulate controls will reduce Pb and Cd.

REGULATORY ALTERNATIVES ABOVE FLOOR: Above the floor alternatives have not been examined at this point. However, the Hazardous Waste MACT and Medical Waste MACT could be reviewed to form a plan for completing this task. Based on the high level of control and regulation of this subcategory, it is unlikely there is justification to regulate beyond the floor for particulates, SO_2, HCl, NOx or CO. However, there might be justification for additional controls for Hg, Pb, Cd, or dioxins, if they are present.

STATUS OF DATA COLLECTION AND ANALYSIS: A list of those facilities for which emissions test data are available has been developed and spreadsheets have been developed which provide detail regarding the air pollution control devices on each surveyed source and what Section 129 pollutant(s) each may control. The spreadsheet has been arranged according to how effectively each device can control a given pollutant in order to provide some insight into what type of control may be appropriate for selection as MACT floor for existing and new units.

ISSUES AND NEEDS: A review of the State regulations for combustion emissions needs to be completed. There is also a need to confirm that size, throughput, or type of operation does not impact emissions or the cost of control and therefore subcategorization.

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE DESCRIPTIONS, NUMBER OF UNITS, AND PERCENTAGE OF UNITS IN DATABASE

1,4 butanediol heavy ends, 1, 0.42%
5% office paper, 95% paint sweepings and paint booth, 1, 0.42%
50-500 ppm PCB's/other (unidentified), ,1 0.42%
98% water, 2% anti-static liquid mixed with water, 1, 0.42%
Activated sludge from a pharmaceutical manufacturing plant wastewater treatment, 1, 0.42%
Aniline/other (unidentified), 1, 0.42%
Biological secondary sludge from aerobic treatment of industrial wastewater, 1, 0.42%
By-product waste, 1, 0.42%
Carbon black, 2, 0.84%
Coal tar waste/mixed industrial, 1, 0.42%
Confidential papers, 1, 0.42%
Contaminated trash from ammunition production lines, 1, 0.42%
Coproduct of partial acidation process, 1, 0.42%
Decorative laminate/cast polymer scrap, 1, 0.42%
Diesel fuel, 2, 0.84%
Disposal of pyrophoric samples, 1, 0.42%
Distillate from reactors containing approximately 7 NT % TOC, 1, 0.42%
Distillate or water by-product generated by condensation, 1, 0.42%
Ethyl acetate isopropanol, 1, 0.42%
Fabric scraps and lint, 1, 0.42%
Fiber paint booth filters & paper waste ,1, 0.42%
Fiberglass overspray filters loaded with overspray from finish system ,1, 0.42%
Fibers waste, 2, 0.84%
Fumes from reactors, 1, 0.42%
Gauzes, dispensary wastes, oily rags, floor sweepings, plastics, paper, and cardboard, 1, 0.42%

Illegal drugs and combustible contraband, 1, 0.42%
Industrial sludge, 1, 0.42%
Industrial solid waste (non-hazardous) ,1, 0.42%
Industrial waste materials, 1, 0.42%
Industrial waste/waste oil ,1, 0.42%
Industrial wastewater sludge, 6, 2.52%
Industrial wastewater sludge from bulk pharma-chemical manufacturing, 1, 0.42%
Lacquer dust from spray booth clean up as well as scrapings and filters, 1, 0.42%
Lead-free, chrome- free paint sludge (~10% solvent, ~90% solids), 1, 0.42%
Liquid hydrocarbon wastes containing salts and catalyst, 1, 0.42%
Liquid waste from air oxidation process, 1, 0.42%
LPG, 10 ,4.20%
Medical waste, 1, 0.42%
Microfiche (15%), paper (5%), and Mylar/mixed, 1, 0.42%
Mineral spirits fumes burned off without condensation, 2, 0.84%
Mixture containing 2/3 common trash, 1/3 non-hazardous chemicals (plastics, foam etc.), 1, 0.42%
Mixture of combustible waste such as non-recycled paper, cardboard carton, floor sweepings, 1, 0.42%
Molded paper articles containing nitrocellulose, 1, 0.42%
Molded paper articles containing nitrocellulose, 1, 0.42%
Multiple effect evaporator concentrate; concentrated blowdown from cooling tower, 1, 0.42%
Municipal/commercial solid waste: type 0 - trash, 3, 1.26%
N-methyl pyrrolidine residue, 1, 0.42%
Natural gas, 43, 18.07%
NCGS from pulping operations, 1, 0.42%
Nitric acid fumes as No 3 and NO 2, 2, 0.84%
No. 2 distillate, 15, 6.30%
No. 6 residual oil, 1, 0.42%
Non-hazardous industrial solid waste, including off-spec pharmaceutical and other, 1, 0.42%
Non-hazardous liquid distillates generated from pioneer's, 1, 0.42%
Non-hazardous, non-RCRA, non-DOT regulated polyols, 1, 0.42%
Off spec pharmaceutical products & packaging components, 1, 0.42%
Off-gas from air oxidation process, storage tank vents, distillation vents, 1, 0.42%
Off-specification diaper raw materials and trim waste, paper, corrugated cartons, plastic, 1, 0.42%
Oil filters & process filters oil & gas, 1, 0.42%
Oil filters, oil field trash, process filters ,1, 0.42%
Oil soaked pads - oil absorbent bags from floor drains, 1, 0.42%
Oily absorbents used for soaking up spilled motor and hydraulic oils, 1, 0.42%
Organic fumes from condensation reaction of unsaturated polyester resin, 1, 0.42%
Oxidized waxes and petroleum, 1, 0.42%
Paint booth filters & paint dust, 1, 0.42%
Paint both filters containing cured 2-part urethane paint; floor sweepings, 1 ,0.42%
Paint filters and varnish dust, 1, 0.42%
Pallets, 2, 0.84%
Paper mill sludge from waste treatment plant-deink tissue mill, 1, 0.42%
Paper slurry containing nitrocellulose, 2 ,0.84%
Pathological: animal remains, 1, 0.42%
Petrochemical process gas, 1, 0.42%
Phosphate cleaner & paint waste, 1, 0.42%
Phosphate cleaner waste, 1, 0.42%
Plastics ,5, 2.10%
Polypropylene carpet backing, 1, 0.42%
Process off-gas from herbicide production, 1, 0.42%
Process wax composed of fillers and resins, 1, 0.42%
Pulp mill non-condensible gases , 1, 0.42%
PVC/styrene/abs/hdpe/ldpe/ (plastics), 1, 0.42%

Quantity of wax, 1, 0.42%
Rectified methanol from pulpmill condensates, 1, 0.42%
Refined petroleum contaminated debris, 1, 0.42%
Regulated medical waste such as discarded wipes, gauze, gowns, gloves, bandages, 1, 0.42%
Residue from herbicide intermediate production, 1, 0.42%
Returned pharmaceutical products with packaging (non-hazardous), 1, 0.42%
Single chamber incinerator, 1, 0.42%
Solids from manufacturing and product storage, 1, 0.42%
Solids/other (unidentified), 1, 0.42%
Stoddard calibration fluid, 1, 0.42%
Sulfur-free organic by-product/other (unidentified), 1, 0.42%
Tablets, capsules, non-corrugated carton, 1, 0.42%
Tar oil; similar to no 6 fuel oil, 16,000 btu/lb, 1, 0.42%
Turpentine and methanol from foul condensate stripper, 1, 0.42%
Undefined solid waste (explosives), 1, 0.42%
Undefined solid waste (fertilizer)/other (unidentified), 1, 0.42%
Undefined solid waste (laboratory waste)/other (unidentified), 1, 0.42%
Undefined solid waste (metal coating)/finishing waste, 3, 1.26%
Undefined solid waste (photofinishing)/photo processing, 1, 0.42%
Undefined solid waste (toilet preparations; cosmetics, 1, 0.42%
Undefined waste (plastics, synthetic materials, etc), 1, 0.42%
Unknown/finishing wastes, 1, 0.42%
Used air filters from paint booths, dirty rags, drip paper from paint booths, 1, 0.42%
Vapor from stoddard calibration fluid, 1, 0.42%
Vegetable oil, coconut oil, rice oil, silicone oil, 1, 0.42%
Vent gases produced in manufacturing and product storage, 1, 0.42%
Vinyls/other (unidentified), 1, 0.42%
Volatile organic compounds from pioneer's, 1, 0.42%
Waste activated charcoal and waste diatomaceous earth used as filter media, 1, 0.42%
Waste carbon black, 1, 0.42%
Waste ethical drugs, sweeping, etc., waste narcotic controlled drugs, 1, 0.42%
Waste excess activated sludge from permitted wastewater treatment plant, 1, 0.42%
Waste fluids, 3, 1.26%
Waste fluids/other (unidentified), 2, 0.84%
Waste from fibers processing, primarily fishing, 2, 0.84%
Waste lint/other (unidentified), 1, 0.42%
Waste lubrication oils, 1, 0.42%
Waste oil, 7, 2.94%
Waste type 1, 1, 0.42%
Waste water sludge from auto painting, 1, 0.42%
Water used to wet rags for wiping off furniture parts is evaporated in the incinerator, ,1 0.42%
Water vapor with varying amounts of organics, 1, 0.42%
Water with varying amounts of organics, 1, 0.42%
Wax composed of fillers and resins, 1, 0.42%
Wood: dried milled lumber, 1, 0.42%
Unspecified, 18, 7.56%
Total in database, 238

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE COMBUSTION DEVICES AND NUMBER OF DEVICES IN DATABASE

Catalytic, 2
Extrusion incinerator, 1
Excess air, fluid bed, single batch fed, 2
Fluidized-bed, 1
Suspension firing, fluid bed, continuously fed, 2
Burn-off oven, multi-chamber, excess air, intermittent batch fed, 2
Burn-off oven, multi-chamber, starved air, single batch fed, 1
Fixed hearth, multi-chamber, excess air, intermittent batch fed, 10
Fixed hearth, multi-chamber, excess air, single batch fed, 3
Fixed hearth, multi-chamber, intermittent batch fed, 4
Fixed hearth, multi-chamber, single batch fed, 2
Fixed hearth, multi-chamber, starved air, intermittent batch fed, 3
Multi-chamber, continuously fed, 2
Multi-chamber, continuously fed, down fired, 3
Multi-chamber, continuously fed, sudden expansion, 3
Multi-chamber, excess air, automatic feeder, 8
Multi-chamber, excess air, continuously fed, 3
Multi-chamber, excess air, intermittent batch fed, 4
Multi-chamber, excess air, starved air, 4
Multi-chamber, intermittent batch fed, 3
Multi-chamber, intermittent batch fed, continuously fed, 3
Multi-chamber, single batch fed, 12
Multi-chamber, starved air, single batch fed, 4
Multiple chamber (could be starved or excess air), 5
Multiple hearth, 1
Multiple hearth, continuously fed, 4
Multiple hearth, excess air, continuously fed, 2
Pathological, fixed hearth, multi-chamber, excess air, starved air, intermittent batch fed, medical, 2
Pathological, multi-chamber, intermittent batch fed, medical waste, rocking kiln, 6
Spreader stoker, multi-chamber, excess air, single batch fed, 2
Suspension firing, multi-chamber, intermittent batch fed, 2
Rotary hearth, 3
Rotary kiln, 4
Rotary kiln, multi-chamber, continuously fed, 2
Rotary kiln, multi-chamber, excess air, intermittent batch fed, 5
Fire tube, induced draft, rotary kiln, multi-chamber, excess air, continuously fed, 3
Metals recovery, rotary hearth, 4
Single chamber, 13
Single chamber, continuously fed, 12
Single chamber, down-fired thermal oxidizer liquid incinerator, 3
Single chamber, excess air, continuously fed, 11
Single chamber, excess air, fluid bed, continuously fed, 3
Single chamber, excess air, single batch fed, 1
Single chamber, single batch fed, 3
Burn-off oven, single chamber, excess air, intermittent batch fed, 2
Fixed hearth, single chamber, excess air, 2
Single chamber, single batch fed, with after burner, 2
Suspension firing, single chamber, excess air, continuously fed, 3
Burn-off oven, 2
Continuously fed, 5
Excess air, continuously fed, 4
Furnace, 1

Incinerator, 3
Incinerator, metals recovery, pathological, single batch fed, 4
Oxidation plant, 1
Pathological, fixed hearth, starved air, single batch fed, 3
Suspension firing, excess air, continuously fed, 2
Unspecified incinerator, 6
Unspecified incinerator/UR 1500, 2
Used oil heater, 1
Total in database, 316

LIST OF MISCELLANEOUS INDUSTRIAL AND COMMERCIAL WASTE INCINERATION EMISSION CONTROL DEVICES AND NUMBER OF DEVICES IN DATABASE

Direct flame afterburner, 20
Direct flame afterburner - heat exchange, 2
Electrostatic precipitator, high efficiency, 3
Fabric filter, high temperature, 3
Fabric filter, medium temperature, 6
Impingement plate scrubber, 1
Mist eliminator, high velocity, 4
Mist eliminator, low velocity, 1
Multiple cyclone w/o fly, 2
Packed-gas absorption column, 4
Single cyclone devices, 5
Venturi scrubber, 15
Wet cyclonic separator, 5
Wet scrubber, high efficiency, 6
Wet scrubber, medium efficiency, 3

SUBCATEGORY NAME: Wood and Wood Waste Incinerators

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (OSWI).

GROUPINGS WITHIN SUBCATEGORY:

Milled Solid and Engineered Wood Wastes
Harvested Wood and Agricultural Wastes
Construction, Demolition, and Treated Wood Wastes

POPULATION STATISTICS:

All units identified in the database as combusting materials associated with agricultural activities were verified. Of the 18 units listed in the database, no units were found to be incinerators actually combusting agricultural types of materials. Seven units were no longer in existence, five units were small MWC's, four units were combusting materials within the purview of other subcategories, one unit was a boiler, and one unit was a process heater. Incineration units dedicated to the combustion of agricultural waste are few to non-existent. If such units exist, these units are small to very small in nature.

Twenty two units were identified within the database as combusting various types of wood materials. Each of these units were verified -- nine units were identified as being "air curtain" incineration units, seven units were identified as small to very small incineration units without specific pollution controls combusting various types of wood materials, two units were MWC's, one unit was a teepee, one unit was an open burning operation, one unit was a boiler, and one unit is no longer in operation.

The identified incineration units are believed to reasonably represent the domestic population of wood incinerators and to include the bulk of existing units. The geographic coverage of the database includes all States where such units would be expected to be concentrated. The wood incinerators data should be at least as representative as EPA's ICCR databases as a whole. Due to the incentive to burn wood materials for heat recovery (e.g., in boilers), the population of wood incinerators is believed to be static or in decline.

Air curtain units are properly addressed under Section 129 g(1) in which air curtain units are exempted from rulemaking if they burn wood waste, yard waste, and clean lumber and comply with opacity limits as set forth by the Administrator.

There may be more teepee and open burning operations combusting wood than has been identified in the database. Various State permit conditions dealing with these units provide valuable guidance and should be consulted and reviewed prior to the setting of any federal conditions or standards. The ICCR Coordinating Committee recommends consideration of basing any federal recommendations for teepees and open burning on the State rules.

All seven units identified as incineration units combusting various materials consisting of wood are small to very small in size. These units were also found to have no specific pollution control and were operating infrequently on an as needed or batch basis. Therefore, these units are difficult to control outside of good combustion practices. Although the number of units identified in the database combusting these materials is small, the database is correct in that most wood type materials are combusted as fuels in boilers.

MATERIALS COMBUSTED:

Milled Solid and Engineered Wood Wastes. Wastes and residues resulting from woodworking manufacturing activities. The specific characteristics of these materials vary depending on the specie of wood (e.g., pine, oak, and poplar) and the engineered wood (e.g. particleboard, plywood, and fiberboard) used. The proportion of adhesives, glues, and binders normally found in engineered wood ranges from 2 to 15 percent by weight depending on the product. The composition is variable and contains no more than 5 percent by weight of other contaminants such as cardboard, paper, paints, and solvents.

Harvested Wood and Agricultural Wastes. Wastes and residues resulting from land clearing, orchard, silviculture, nursery, greenhouse, agricultural, and forest management activities and sawmill operations. The combustion characteristics of these materials vary, and the moisture content typically ranges from 20 to 60%. Some wastes may contain residual chemical compounds from pesticide and herbicide treatment of vegetation. The composition contains no more than 5 percent by volume of contaminants such as sand, dirt, cardboard, and paper.

Construction, Demolition, and Treated Wood Wastes. *Construction wastes* are wastes and residues resulting from the construction, remodeling, and repairing of individual residences, commercial buildings, and other structures. The composition is variable and generally includes pallets, forming and framing lumber, treated lumber, shingles, tar-based products, plastics, plaster, wallboard, insulation material, plumbing, heating, and electrical parts. *Demolition wastes* are generally the same as construction wastes but may include broken glass, painted or contaminated lumber, chemically treated lumber, white goods, and reinforcing steel. *Treated wood wastes* are wastes and residues resulting from the treatment of wood products that are impregnated or otherwise treated with various preservatives (e.g., creosote, copper compounds, arsenic compounds, pentachlorophenol, [additional preservatives to be added]) for the purpose of protecting or otherwise extending the structural properties of the wood. The composition is variable and contains such contaminants as organic and inorganic chemicals, metals, oils, paint, solvents, and pigments.

COMBUSTION DEVICE: Includes single and multi-chamber and fluidized bed incinerators (i.e., devices without heat recovery) of various sizes, and also open burning, air curtain incinerators and teepees. The types of waste combusted in each of these combustion devices is illustrated in the following matrix.

COMBUSTION DEVICE	WOOD AND WOOD WASTE TYPE		
	Milled solid and engineered	Harvested wood and agricultural	Construction, demolition, and treated
Open burning		✔	?
Air curtain	?	✔	?
Teepee	✔	?	?
Incinerator	✔	?	✔

BASIS FOR SUBCATEGORY BOUNDS: Waste and equipment type and possibly size; other criteria are being considered.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants.

FLOOR LEVEL OF CONTROL: It may be difficult to identify a MACT floor, based on the absence of any control devices among those units found in the inventory and survey databases. State regulations and permits were not found for these units, except for several opacity limits. A best controlled similar unit for determining the new unit MACT floor was not identified.

REGULATORY ALTERNATIVES ABOVE FLOOR: Yet to be evaluated, but good combustion practices, source separation, particulate controls, scrubbers, ESPs, afterburners, and secondary combustors should be considered.

STATUS OF DATA COLLECTION AND ANALYSIS: The survey database indicates six units have test data, and EPA has taken action to obtain these test reports. The database indicates 11 units to have some kind of control, but independent verification identified no units as having controls. Two units were identified as being teepee burners and 2 units were identified as air curtains.

ISSUES AND NEEDS: Test data are lacking. Additional testing may be needed for milled, harvested, and treated wood wastes, although due to the small number of units in the category, the ICCR Coordinating Committee does not recommend testing at this time. Instead, the Committee believes that adequate data of good quality currently exist within State permit conditions and regulations and that these data should be used to establish emission limits.

OTHER COMMENTS:

It is unclear if the applicability of an agricultural subcategory is valid. Although independent verification of the 18 facilities listed as agricultural facilities in the database indicated that no such facility or unit exists, this category should continue to be considered until a more definitive determination is made. For emissions data, a NY/EPA test summary, tests reported in the 1998 EPA dioxin emissions inventory report, and test data reported in the ICR survey responses are available for review. A number of test reports identified in the EPA ICR have been requested by EPA.

It may be reasonable to combine the three wood and wood waste groupings into a single category (e.g. the miscellaneous industrial and commercial wood waste subcategory), since there are so few wood and wood waste units and there are similarities in emissions and controls. The Committee recommends that EPA first consider whether separate emission limits can be established for each wood and wood waste grouping. If this proves to be infeasible, the merging of wood and wood waste into a single miscellaneous industrial and commercial wood waste subcategory may be necessary.

A list of wood and wood waste facilities, unit types, and controls is presented below. This list was initially compiled from the inventory and survey databases. Facilities found not to be in operation or otherwise misclassified were deleted from the initial list, resulting in the revised list presented below.

ICCR#	Facility Name	Unit Type	Type of Controls
450130037	Malphrus Construction #2	Air Curtain	None
220330013	La Skid and Pallet	Air Curtain	None
19059W350	Stylecraft, Inc	Incinerator	None
19059W350	Stylecraft, Inc	Incinerator	None
19059W350	Stylecraft, Inc	Incinerator	None
300670003	Park Lumber Company	Teepee	None
470830063	Imperial Fabricating Company	Incinerator	None
470890001	Burroughs-Ross Colville	Open Burning	None
47163A280	City of Kingsport	Air Curtain	None
47005A246	City of Alcoa	Air Curtain	None
120990233	Marks Landscaping & Paving	Air Curtain	None
530470015	Zosel Lumber	Incinerator	None
511750050	Atlantic Wood	Air Curtain	None
160490002	L.D. McFarland	Air Curtain	None
170312435	Service Products Inc	Incinerator	None
390775014	R.R. Donnelley & Sons	Incinerator	None
482010110	Cagle Constructors	Air Curtain	None
482010110	Cagle Constructors	Air Curtain	None
482010110	Cagle Constructors	Air Curtain	None
550750390	Fruday Canning Corp	Incinerator	None

SUBCATEGORY NAME: Pathological Waste Incinerators and Crematories

ASSIGNED CAA Section (ICWI OR OSWI): Section 129 (OSWI).

GROUPINGS WITHIN SUBCATEGORY:

By mass burn rates as follows: less than 100 lb/hr; 100 to 500 lb/hr; over 500 lb/hr. These groupings were made based on categories typically seen in the field, with each group tending to have a distinct design, complexity, size, and method of utilization. Differences in emission rates due to design, waste profiles, or any other factors are not known due to insufficient data. Profiles for each of these groups are given below. Grouping is also possible by the amount and composition of material burned that is not animal or human remains.

Less than 100 lb/hr mass burn rate

Typical user profile - primarily poultry farmers; secondary small animal crematories, veterinary centers, humane societies, and pharmaceutical companies. Little or no training on operating parameters by a qualified source.

Annual operating hours per unit - unknown

Typical waste profile - primarily poultry carcasses; secondarily small animal remains, the bags/containers used to collect and transport the waste material, and animal bedding.

Typical design profile - for poultry units: single chamber systems; fueled with #2 fuel oil, LP gas, or natural gas; no air or temperature controls; manual operating system; batch fed; no add-on emission controls.

100 to 500 lb/hr mass burn rate

Typical user profile - primarily human crematories; secondarily: animal crematories; veterinary clinics; humane societies; and pharmaceutical companies. Training often required and usually conducted by manufacturers or service organizations.

Annual operating hours per unit - 700

Typical waste profile - primarily human remains and associated containers; secondarily: animal remains, the bags/containers used to collect and transport the waste material, and animal bedding.

Typical design profile - retort and in-line systems, as described below; fueled with natural gas, LP gas, or #2 fuel oil; limited air controls; limited temperature controls; manual control system; batch fed; no add-on emissions control devices.

Greater than 500 lb/hr mass burn rate

Typical user profile - primarily animal disposal systems for hospitals, animal control facilities, and research facilities.

Annual operating hours per unit - 1000

Typical waste profile - primarily animal remains, the bags/containers used to contain them, and animal bedding.

Typical design profile - multi-chamber design as described below; fueled with natural gas, LP gas, or #2 fuel oil; air and temperature controls; automatic control systems; mechanical feed with intermittent charging; no add-on emissions control devices.

POPULATION STATISTICS:

Nationwide estimate by size groupings:

Less than 100 lb/hr - possibly several thousand units, however, many of these units are not permitted or registered and therefore are under-represented in the database.

100 to 500 lb/hr - 2000 units, based on information from the Cremation Association of North America (CANA) and leading equipment manufacturers.

Over 500 lb/hr - 100 units, based on communication with manufacturers.

The population estimates shown are significantly higher than is indicated by the database, especially in the case of the less than 100 lb/hr units

MATERIALS COMBUSTED: Pathological waste is waste material consisting of only human or animal remains, anatomical parts and/or tissue, the bags/containers used to collect and transport the waste material, and animal bedding, if applicable *(from the HMIWI MACT)*.

COMBUSTION DEVICE:

These combustors are generally single or multiple chamber designs. They are fueled with fossil fuel and operate with excess air. The wastes, consisting of at least 90% by mass pathological waste as defined above, are fed as single batches or intermittently fed. (The ICCR Coordinating Committee recommends that the 90 percent limit be determined on a daily basis, but at no time shall any batch consist of less than 70 percent pathological material.) Typically these combustors have no add-on emission control devices.

A crematory incinerator is a pathological waste incinerator which is primarily used to reduce single batches of human or animal remains and their containers (pathological waste) to their basic elements with the intent of recovering the cremated remains for memorialization purposes.

Pathological waste combustors can be classified into the following design categories:

Retort incinerators - multiple chamber incinerator designs in which the secondary chamber is located directly beneath the primary chamber. The purpose of this configuration is that the hearth of the primary chamber is heated by the products of combustion flowing through the secondary chamber. This type of design is superior for controlling fluids involved in the incineration of human and animal tissue. Because the temperature of the secondary chamber affects the temperature of the primary chamber, excessive temperature in the secondary chamber (above 1600^{o}F) has a tendency to increase emissions due to the accelerated burning rate of the charge.

In-line incinerators - similar to the retort design in that the chambers share a common wall. In the in-line design the secondary chamber is not underneath the hearth, but is behind the primary chamber. This design is less effective than the retort in destroying the fluids from human and animal tissue.

Multi-chamber incinerators - multiple chamber incinerator designs consisting of separated primary and secondary chambers. The secondary chamber is generally located above the primary chamber with the two chambers having no common ceilings, hearth, or walls between them. The temperature in the secondary chamber has little or no influence on the primary chamber temperature. This design is preferable in processing non-tissue wastes.

BASIS FOR SUBCATEGORY BOUNDS: As regulation development proceeds, it may be beneficial to make subdivisions based on size, waste mix, or other criteria.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 pollutants.

FLOOR LEVEL OF CONTROL (EXISTING): No control. Good combustion practice may or may not serve to identify a MACT floor.

REGULATORY ALTERNATIVES ABOVE FLOOR (EXISTING): See attached “Potential Incinerator Control Options” and “Recommendations for Pollution Prevention Options”.

BEST CONTROLLED SIMILAR SOURCE (FLOOR-NEW): No units have been identified that achieve a level of emissions reduction that is superior to good combustion practice.

REGULATORY ALTERNATIVES ABOVE FLOOR (NEW): See attached “Potential Incinerator Control Options” and “Recommendations for Pollution Prevention Options”.

STATUS OF DATA COLLECTION AND ANALYSIS: Some emission test reports on criteria pollutants available and additional test reports identified in the EPA ICR have been requested by EPA. However, the available data are incomplete and the information from the ICR respondents indicating they have information on the use of add-on emissions control devices has not been evaluated.

ISSUES AND NEEDS:

Data - (1) Emissions data for the majority of sources for all Section 129 pollutants are limited. (2) There is uncertainty regarding the number of units in the less than 100 lb/hr grouping -- these units are not represented in the databases.

Subcategorization - Subcategories used herein (mass burn rate/hr) do not necessarily constitute a recommendation to EPA on subcategorization. Other ways of subcategorizing sources are possible, e.g., by use [human crematoria vs. non-human (animal waste) incinerators]. The best approach may be no subcategorization at all. Appropriate subcategories should be determined by emissions test results.

Emissions testing (special concerns) - Because of the frequent siting of the 500 lb/hr and under incinerators in residential and light commercial areas, the ICCR Coordinating Committee urges EPA to adopt the test plan recommended by the Committee so as to determine the levels of Section 129 pollutants (especially metals, dioxins, and furans). The impact of dental amalgams containing mercury on mercury emissions from crematories, and the impact of varying amounts of bedding and "other" materials in animal waste incinerators, should be evaluated.

OTHER COMMENTS:

Control option recommendations - The ICCR Coordinating Committee recommends good combustion practices be adopted, including 1 second secondary chamber retention times and minimum secondary chamber temperatures of 1600 to 1800 ^{o}F based on design types as follows: 1600^{o}F for units 500 lb/hr and under, in-line and retort types; 1800^{o}F for units greater than 500 lb/hr, multi-chamber type. In addition, the Committee recommends the use of combustion temperature controls.

Population estimates - Units in the less than 100 lb/hr grouping will decrease due to alternate methods of disposal such as composting. Units in the 100 to 500 lb/hr range will increase slightly due to an approximate increase of the human cremation rate of 4% per year until 2010 (based on statistics from the Cremation Association of North America). The greater than 500 lb/hr unit population will remain static or decrease slightly over time.

POTENTIAL INCINERATOR CONTROL OPTIONS
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for "Substantial" Emission Reduction											COMMENTS
	PM[a]		Op[b]	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
	f	t										
No control												Many incinerators are uncontrolled due to their small size, absence of regulations, and/or absence of demonstrated cost effective control technology.
Good combustion design and practice	✔	✔	✔				✔				✔	For example, control of temperature and feed rate and use of supplemental combustion/ secondary chamber. Other pollution prevention options are available (see attached document "Recommendations for Pollution Prevention Options for Combustion Practice").
Baghouse/ESP	✔	✔	✔					✔	✔	✔		There are no baghouse systems being manufactured for units this small. ESPs tend to be overly expensive for small incinerator applications. High temperatures may preclude the use of baghouses without an upstream scrubbing system or upstream temperature reduction device. Dioxin generation is a possibility.
Thermal oxidizer/afterburner			✔									Only applicable to single chamber units. Effectiveness with Section 129 pollutants unknown. Generates NOx and CO.

POTENTIAL INCINERATOR CONTROL OPTIONS (Continued)
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for "Substantial" Emission Reduction											COMMENTS
	PM[a]		Op[b]	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
	f	t										
Cyclone/multiclone		✔	✔									Not very effective on these units because particle sizes are small.
Wet scrubber (low pressure or venturi) w/o water recycle		✔	✔	✔	✔							Will not provide significant improvement of emissions since the particle sizes on these units are small and good combustion efficiency is already being achieved. Acid gas formation could be a problem if water recycle is used in the presence of sulfur and chlorine. Some control of metals may occur (the presence of chlorine will enhance the removal of Hg). Creates water pollution
Dry acid gas/PM scrubbing system, including baghouse (DSI, dry sorbent injection system)	✔	✔	✔	✔	✔			✔	✔	✔	✔	Can be a highly effective control system, although cost may be prohibitive, especially for small units like these. Carbon injection for Hg control can be added at little incremental cost. Creates solid (possibly hazardous) wastes.
Semi-dry acid gas/PM scrubbing system (spray dryer and baghouse)	✔	✔	✔	✔	✔			✔	✔	✔	✔	Performs even better than DSI system, but costs are significantly higher. Carbon injection for Hg control can be added at little incremental cost. Creates water pollution and solid wastes.

POTENTIAL INCINERATOR CONTROL OPTIONS (Continued)
Pathological Waste Incinerators and Crematories

CONTROL OPTION	Potential for "Substantial" Emission Reduction											COMMENTS
	PM[a]		Op[b]	SO_2	HCl	NOx	CO	Pb	Cd	Hg	D/F	
	f	t										
Low-NOx burners, combustion chamber design, SNCR (ammonia injection)						✔						Applicability of low-NOx burners to these types of small incinerators is questionable due to high excess air requirements. Can create CO and NH_3 emissions.

[a]f = fine particulate matter; t = total particulate matter.
[b]OP = opacity

ICCR Coordinating Committee Recommendations for Pollution Prevention Options for Combustion Practice

August 31, 1998

The following **good combustion practice** techniques are applicable to pathological waste incinerators and crematories: operator practices; maintenance knowledge; maintenance practices; residence time, temperature, turbulence; fuel/waste mix, quality, and handling (especially for pathological).

The ICCR Coordinating Committee recommends secondary combustion chamber residence times of 1 second and minimum secondary combustion chamber temperatures of 1600°F to 1800°F based on design types as follows: 1600°F for units (retort, in-line) 500 lb/hr and under; 1800°F for units (multi-chamber) over 500 lb/hr. In addition, the Committee recommends the use of combustion temperature controls for all unit types.

Operator training requirements are recommended for these units as well. Training content, hours, and qualifications should take into account that these units do not have complex methods of operation.

The following **metrics** are most suitable for these units: mass emissions/volume and, alternately, mass emissions/waste input. Mass emissions/volume of flue gas is comparable for all combustor sizes, provided auxiliary fuel is used. However, it is known that electrically heated crematories burn with equivalent or lower mass emissions/mass of waste input, yet higher mass emissions/volume of flue gas. Appropriate units for mass emissions/mass of waste input could be lb/100 lb burned.

Waste accounting and recordkeeping, work practice standards, waste constituent standards and de minimis levels would be applicable to non-tissue feed constituents. Certifications from suppliers of containers could be required, for example.

Several **MACT options** are appropriate. The options could be: a choice between the two metrics described above; a feed *de minimis* standard, which would be most applicable to the non-tissue material feed; and/or a list of best operating practices determined to achieve comparable emission reductions to the numeric emission limit.

SUBCATEGORY NAME: Drum Reclaimer Furnaces

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (ICWI).

GROUPINGS WITHIN SUBCATEGORY: None.

POPULATION STATISTICS:

ICCR Inventory Database - 38 facilities, 44 units
Trade group estimate - 55 units (national population)

Because in recent years steel drum production rates have remained unchanged, the number of drum reclamation furnaces is not expected to increase.

MATERIALS COMBUSTED: The drum reclaimer furnace is used to reclaim steel containers, most often 55-gallon drums, for reuse or to prepare them for recycling. Drums are prepared for cleaning by abrasive shot blasting by being processed through the furnace, where interior and exterior coatings and residues are burned or pyrolyzed. Drums must be empty as defined by RCRA prior to furnace processing, and thus, not subject to Section 3005 permitting requirements. Natural gas is most often fired as the primary fuel in drum furnaces.

COMBUSTION DEVICE: The typical drum reclaimer furnace is a semi-continuous tunnel furnace equipped with a high temperature thermal oxidizer. Heat inputs listed in the ICCR inventory database range from 1.2 MMBtu/hr to 15.6 MMBtu/hr.

BASIS FOR SUBCATEGORY BOUNDS: Due to the easy identification and substantial number of these units in the ICCR inventory database, their unique purpose, and the potential for emissions of Section 129 pollutants, they were subcategorized for further study. Drum reclaimer furnaces are distinct from parts reclaimer burnoff units because the drum reclaimer furnaces tend to be larger, with greater heat input, are semi-continuous rather than batch, and hazardous constituents potentially present in the drums may result in emissions different from those of parts reclaimers.

POLLUTANTS CONSIDERED FOR REGULATION: These include the complete set of Section 129 pollutants: PM, SO_2, CO, NOx, Pb, and HCl, dioxins/furans, Hg, and Cd. PM (RM5) emissions are likely to be fairly well-characterized, and there exist a number of State regulations on PM emissions from these furnaces. However, queries of the SURVEYV2.MDB database indicate that no HAPs data are available. The 112(c)(6) emissions inventory lists a 2,3,7,8-TCDD TEQ emission factor of 1.09E-07 lbs per 1000 drums burned.

FLOOR LEVEL OF CONTROL: Based on the inventory database, the use of thermal oxidation should identify a MACT floor. Practices such as ensuring that the drums are empty of all materials that can be reasonably removed by techniques other than combustion, and thermal oxidizer preheat prior to introducing drums into the furnace, are common and may also serve to identify a MACT floor, although this remains to be confirmed. Because the "best controlled similar unit" appears to be units in the inventory and survey databases that are controlled by thermal oxidizers, the use of thermal oxidation should also identify a MACT floor for new units. (Although the inventory database lists a catalytic afterburner w/HX as a control device in use on one drum reclaimer furnace, it is doubtful that this control device is actually in use, and it does not appear in the survey database.)

REGULATORY ALTERNATIVES ABOVE FLOOR: Since the floor control does not control acid gases, a spray dryer or wet scrubber may be considered, depending on emissions of acid gases. Similarly, Cd and Pb are not controlled in a thermal oxidizer, and this suggests considering a fabric filter. In addition, good combustion practice may be applicable.

STATUS OF DATA COLLECTION AND ANALYSIS: Based on SURVEYV2.MDB, there appear to be no HAPs emission test data available for drum reclaimer furnaces.

ISSUES AND NEEDS: There is a paucity of emissions data for certain Section 129 pollutants.

OTHER COMMENTS: Recommendations for stack testing were forwarded to EPA by the ICCR Coordinating Committee. A summary of control devices for drum reclaimer furnaces in the inventory and survey databases is presented below.

Air Pollution Control Devices for Drum Reclaimer Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
021	Direct Flame Afterburner	4	9%
022	Direct Flame Afterburner w/HX	1	2%
---	Units not listed	39	89%

Air Pollution Control Devices for Drum Reclaimer Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
000	None	8	18%
021	Direct Flame Afterburner	13	30%
020	Catalytic Afterburner w/HX	1	2%
---	Units not listed	11	50%

SUBCATEGORY NAME: Parts Reclaimer Burnoff Units

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 (ICWI).

GROUPINGS WITHIN SUBCATEGORY:

Electrical winding reclaimer burnoff units
Non-PVC coated parts reclaimer burnoff units
PVC coated parts reclaimer burnoff units

POPULATION STATISTICS: ICCR Inventory database - 332 units; however, the national populations of the three groupings within the subcategory is estimated as:

Electrical winding reclaimer burnoff units ~300
Non-PVC coated parts reclaimer burnoff units ~1000
PVC coated parts reclaimer burnoff units ~50

MATERIALS COMBUSTED: This type of incinerator is used to reclaim metal parts for reuse in their current form. Coatings such as cured paint, plastisol, or varnish or unwanted parts such as plastic spacers or rubber grommets are burned off a wide variety of metal parts in these units. Plastisol coatings are comprised of polyvinyl chloride and phthalate plasticizer. Plastisol and paint both may contain heavy metal pigments. Metal parts fed to these primarily batch units include paint hooks/racks, electric motor armatures, transformer winding cores, and electroplating racks.

COMBUSTION DEVICE: Parts reclaimer burnoff units are typically small, batch, fossil fuel-fired units. The parts reclaimer burnoff units listed in the ICCR Inventory database list a range of heat inputs from 0.2 MMBtu/hr to 3.7 MMBtu/hr. They are often called burnoff ovens or pyrolysis units and often not recognized as “incinerators.” Operations consist of loading the cold burnoff oven with metal parts, igniting the thermal oxidizer, if present, and main burner (both usually natural gas-fired), and allowing the combustible coating or part to pyrolyze into an fragile ash-like material (often over a period of hours) which may be then mechanically removed or abrasive-blasted off the metal part. Because of the wide variety of parts recycled in these units, facility size varies widely, from small electric motor repair shops to large automobile assembly plants.

BASIS FOR SUBCATEGORY BOUNDS: These units are subcategorized on the basis of similar purpose -- recovering a metal part for reuse in its current form. This places them in Section 129 rather than in Section 112 with the scrap metal recovery units, which are excluded by Section 129(g)(1)(A). They are kept separate from drum reclaimer furnaces because they tend to be smaller batch units and do not have the potential for burning RCRA hazardous wastes.

POLLUTANTS CONSIDERED FOR REGULATION: There is a potential for emissions of all Section 129 pollutants from parts reclaimer burnoff units. Review of SURVEYV2.MDB indicates the existence of HAPs emissions data for at least two electrical winding reclaimer burnoff units (ICCR Facility IDs - 34017W091 and 550570416). A data summary of an old stack test of a PVC coated rack reclaimer burnoff unit indicates the presence of HCl and organic compounds in stack emissions. In addition, any metals present in coating pigments also have the potential to be emitted.

FLOOR LEVEL OF CONTROL: Based on both the inventory and survey databases, the use of thermal oxidation may serve to identify a MACT floor for parts reclaimer burnoff units. Practices such as thermal oxidizer preheat and the removal of excess combustible materials (e.g., paper, rope, cloth, and visibly loose coatings/parts) are common and may also serve to identify a MACT floor, although this remains to be confirmed. Because the "best controlled similar unit" appears to be units in the inventory and survey databases that are controlled by thermal oxidizers, the use of thermal oxidation may also serve to identify a MACT floor for new units. For electrical winding and PVC units, the use of wet scrubbers may serve to identify a MACT floor for new units, although this has yet to be confirmed. (The inventory and survey databases also list some other control techniques, such as fabric filters, that are used sporadically in the industry and may serve to identify a MACT floor for new units for specific pollutants. However, a more detailed study of these devices is needed to determine their effectiveness on the range of units found in the parts reclaimer industry.)

REGULATORY ALTERNATIVES ABOVE FLOOR: The ICCR Inventory database lists a number of units controlled by a wet scrubber or a fabric filter in addition to a thermal oxidizer. While the MACT floor (represented by the performance of a thermal oxidizer) does not control metals or acid gases, control alternatives above the floor should examine scrubbers, spray dryers, and fabric filters. In addition, good combustion practices (GCP) may be applicable.

STATUS OF DATA COLLECTION AND ANALYSIS: Based on review of SURVEYV2.MDB, there appear to be at least two parts reclaimer burnoff units with HAPs emission data and these test reports are being obtained by EPA.

ISSUES AND NEEDS: The ICCR Coordinating Committee has recommended stack testing of two non-PVC coated parts reclaimers burnoff units and two PVC coated parts reclaimers burnoff units. The Committee also recommended an analysis of six cured coatings prior to processing in a parts reclaimer burnoff unit.

OTHER COMMENTS: A summary of control devices for parts reclaimer burnoff units in the inventory and survey databases is presented below.

Air Pollution Control Devices for Parts Reclaimer Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
019	Catalytic Afterburner	1	<1%
021	Direct Flame Afterburner	42	13%
022	Direct Flame Afterburner w/HX	6	2%
025	Staged Combustion	1	<1%

Air Pollution Control Devices for Parts Reclaimer Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
076	Multiple Cyclone w/o Flyash Reinjection (?)	2	<1%
086	Water Curtain (?)	3	1%
101	High Efficiency Particulate Air Filter	1	<1%
212	Air to Fuel Ratio Control	2	<1%
021 & 021	Direct Flame Afterburner & Direct Flame Afterburner	1	<1%
021 & 025	Direct Flame Afterburner & Staged Combustion	3	1%
021 & 028	Direct Flame Afterburner & Steam Injection	1	<1%
022 & 022	DF A.B. w/HX & DF A.B. w/HX	2	<1%
029 & 212	Low Excess Air & Air to Fuel Ratio Control	1	<1%
206 & 212	Low NOx Burners & Air to Fuel Ratio Control (?)	2	<1%
021 & 028 & 025	DF A.B. & Steam Inject & Staged Combustion	1	<1%
024 & 206 & 212	Mod. Furnace & Low NOx Burners & Ato F Ratio (?)	2	<1%
---	Approximate units not listed	261	79%

Air Pollution Control Devices for Parts Reclaimer Units listed in **ICCRV2.MDB**			
CODE(S)	DESCRIPTION	Number	Percent
000	none	38	11%
002	Wet Scrubber - medium efficiency	1	<1%
003	Wet Scrubber - low efficiency	1	<1%
020	Catalytic Afterburner w/HX	2	<1%

Air Pollution Control Devices for Parts Reclaimer Units listed in **ICCRV2.MDB**			
CODE(S)	DESCRIPTION	Number	Percent
021	Direct Flame Afterburner	66	20%
022	Direct Flame Afterburner w/HX	4	1%
024	Modified Furnace/Burner Design	1	<1%
078	Baffle	1	<1%
099	Other Devices	1	<1%
101	High Efficiency Particulate Air Filter	1	<1%
256	No code description available (unknown)	1	<1%
021 & 002	Direct Flame Afterburner & Wet Scrubber - ME	1	<1%
021 & 003	Direct Flame Afterburner & Wet Scrubber - LE	1	<1%
021 & 004	Direct Flame Afterburner & Gravity Collector	1	<1%
021 & 006	Direct Flame Afterburner & unknown	3	1%
021 & 016	Direct Flame Afterburner & Fabric Filter - HT	1	<1%
021 & 028	Direct Flame Afterburner & Steam Injection	1	<1%
021 & 033	Direct Flame Afterburner & unknown	1	<1%
021 & 099	Direct Flame Afterburner & Other Devices	3	1%
021 & 020 & 016	DF A.B. & Catalytic A.B. & Fabric Filter -HT	1	<1%
021 & 016 & 053	DF A.B. & Fabric Filter - HT & Venturi Scrubber	1	<1%
---	Approximate units not listed	201	61%

SUBCATEGORY NAME: Unclassified Metals-Related Incinerators

ASSIGNED CAA SECTION (ICWI OR OSWI): Sections 129 or 112.

GROUPINGS WITHIN SUBCATEGORY: Not applicable.

POPULATION STATISTICS: ICCR Inventory database - 212 units.

OTHER COMMENTS:

The unclassified subcategory represents units that have not been positively identified as drum reclaimer furnaces, parts reclaimer burnoff units, or scrap metal recovery units based on reviews of the inventory and survey databases. The EPA ICR responses have allowed identification of many previously unclassified units as parts reclaimer burnoff units, and it is likely that many currently unclassified units are probably parts reclaimer burnoff units.

Review of the current inventory of unclassified units indicates that many are "incinerators" associated with fabricated metal products industries such as appliance manufacturing, metal pipe coating, automotive parts manufacturing, electrical motor/transformer manufacturing, and pumps and compressors manufacturing. A closer review of the ICR/survey database may reveal whether these incinerators are parts reclaimer burnoff units or plant trash incinerators.

There are entries for semiconductor and electronics manufacturers, as well as ammunition manufacturers. If the units are used to recover the metals content of the electronic equipment or the brass components of ammunition, these could be considered scrap metal recovery units and would be excluded from Section 129.

A summary of control devices for unclassified metals-related units in the inventory and survey databases is presented below.

Air Pollution Control Devices for Unclassified Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
017	Fabric Filter - Medium Temperature	1	<1%
018	Fabric Filter - Low Temperature	6	3%
019	Catalytic Afterburner	1	<1%
021	Direct Flame Afterburner	19	9%
022	Direct Flame Afterburner w/HX	4	2%
025	Staged Combustion	1	<1%
076	Multiple Cyclone w/Flyash Reinjection	1	<1%
099	Other Devices	2	1%

Air Pollution Control Devices for Unclassified Units listed in **SURVEY2.MDB**			
CODE	DESCRIPTION	Number	Percent
001 & 021	Wet Scrubber HE & Direct Flame Afterburner	1	<1%
017 & 075	Fabric Filter MT & Single Cyclone	1	<1%
021 & 016	Direct Flame A.B. & Fabric Filter HT	1	<1%
021 & 017	Direct Flame A.B. & Fabric Filter MT	2	1%
022 & 050	Direct Flame A.B. w/HX & Packed Gas Absorp Col.	1	<1%
025 & 026	Staged Combustion & Flue Gas Recirc	1	<1%
099 & 200	Other Devices & Catalytic Oxidizer	2	1%
001 & 053 & 101	Wet Scrub HE & Venturi & HEPA Filter	2	1%
018 & 020 & 048	Fabric Filter LT & Cat A.B. w/HX & Active Carbon	1	<1%
021 & 028 & 212	DF A.B. & Steam Inject & Air to Fuel Ratio Control	1	<1%
---	Units not listed	164	77%

Air Pollution Control Devices for Unclassified Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
000	none	40	19%
001	Wet Scrubber - High Efficiency	1	<1%
010	Electrostatic Precipitator - High Efficiency	2	1%
013	Gas Scrubber, General	1	<1%
016	Fabric Filter - High Temperature	2	1%
021	Direct Flame Afterburner	28	13%
025	Staged Combustion	1	<1%
070	Sodium-Alkali Scrubbing	2	1%

Air Pollution Control Devices for Unclassified Units listed in **ICCRV2.MDB**			
CODE	DESCRIPTION	Number	Percent
099	Other Devices	1	<1%
255	unknown	4	2%
021 & 008	Direct Flame A.B. & Centrifugal Collector - ME	1	<1%
021 & 016	Direct Flame A.B. & Fabric Filter - HT	1	<1%
022 & 009	DF A.B. w/HX & Centrifugal Collector - LE	1	<1%
---	Units not listed	127	60%

SUBCATEGORY NAME: Solid Mixed Feed Boilers

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 Boilers (TBD)

POPULATION STATISTICS: There are approximately 322 boilers identified in the EPA ICR Survey Version 2.0 database that may fall into this subcategory.

MATERIAL COMBUSTED: Various solid waste materials. These materials are generally co-fired with other non-fossil materials (e.g., wood) or fossil fuels.

COMBUSTION DEVICE: All types of boilers are used, including bubbling and circulating fluidized beds, cell-tubes, cyclone-fired, dutch ovens, fire tubes and water tubes, stokers, wet and dry bottom units, wall-fired and tangentially-fired and package and field-erected units.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes all boilers that fire above a minimum percentage of solid waste materials. These boilers may potentially have different controls than the those on liquid mixed feel boilers due to the difference in the physical state of materials burned.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants

FLOOR LEVEL OF CONTROL: Further analysis is being done.

Existing Sources. At this time, the preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with fabric filters (or an equivalent control technology) for controlling metallic HAPs, scrubbers (or an equivalent control technology) for reducing inorganic HAPs, and good combustion practices for reducing organic HAPs. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

New Sources. Same results as existing sources. In addition, the preliminary MACT floor for new sources for controlling mercury is scrubbers. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

REGULATORY ALTERNATIVES ABOVE THE FLOOR: No regulatory alternatives have been identified for controlling metals and inorganic HAPs. Alternatives above the MACT floor level of control for new and existing sources are carbon absorption for control of organic HAPs and mercury.

STATUS OF DATA COLLECTION AND ANALYSIS: EPA sent an Information Collection Request (ICR) to facilities with boilers burning potential solid waste materials. Responses provided information on the control techniques being used on the boilers in this subcategory. Emission test reports were gathered by EPA on boilers burning the materials combusted. However, only minimal data was obtained for some of the section 129 pollutants and HAPs. EPA has requested additional test reports from ICR respondents, but data gaps are expected to remain.

ISSUES AND NEEDS: Further testing of non-fossil materials and control devices is recommended in order to analyze emissions and set emission limits. A definition of non-hazardous solid waste is needed. The level of solid waste materials that trigger regulation under Section 129 needs to be determined. Further analysis of the boilers and their control equipment in this subcategory is needed to determine if more refined subcategories are necessary.

OTHER COMMENTS: None.

SUBCATEGORY NAME: Liquid Mixed Feed Boilers

ASSIGNED CAA SECTION (ICWI OR OSWI): Section 129 Boilers (TBD)

POPULATION STATISTICS: There are approximately 153 boilers identified in the EPA ICR Survey Version 2.0 database that may fall into this subcategory.

MATERIAL COMBUSTED: Various solid waste liquid materials. These materials are generally co-fired with other non-fossil materials (e.g., wood) or fossil fuels.

COMBUSTION DEVICE: All types of boilers are used, including bubbling fluidized beds, cell-tubes, cyclone-fired, dutch ovens, fire tubes and water tubes, stokers, wet and dry bottom units, wall-fired and tangentially-fired and package and field-erected units.

BASIS FOR SUBCATEGORY BOUNDS: This subcategory includes all boilers that fire above a minimum percentage of solid waste liquid materials. These boilers may potentially have different controls than the solid mixed feed boilers due to the difference in the physical state of materials burned.

POLLUTANTS CONSIDERED FOR REGULATION: Section 129 Pollutants

FLOOR LEVEL OF CONTROL: Further analysis is being done.

Existing Sources. The preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with ESPs (or an equivalent technology) for reducing metallic HAPs, scrubbers (or an equivalent control technology) for reducing inorganic HAPs, and good combustion practices for reducing organic HAPs. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

New Sources. The preliminary MACT floor level of control is equivalent to the emission limit for boilers in this subcategory controlled with fabric filters (or an equivalent control technology) for reducing metallic HAPs, gas absorbers (or an equivalent control technology) for reducing inorganic HAPs, good combustion practices for reducing organic HAPs, and scrubbers for reducing mercury. These results are based on preliminary control techniques rankings for all boiler subcategories. Further analysis will look at combinations of controls.

REGULATORY ALTERNATIVES ABOVE THE FLOOR: Alternatives above the MACT floor level of control are emission limits for boilers controlled with fabric filters (or an equivalent control technology) for metals, and carbon adsorption for organic HAPs and mercury. No above the floor alternatives have been identified for inorganic HAPs.

STATUS OF DATA COLLECTION AND ANALYSIS: EPA sent an Information Collection Request (ICR) to facilities with boilers burning potential solid waste materials. Responses provided information on the control techniques being used on the boilers in this subcategory. Emission test reports were gathered by EPA on boilers burning the materials combusted.

However, only minimal data was obtained for some of the Section 129 pollutants and HAPs. EPA has requested additional test reports from ICR respondents, but data gaps are expected to remain.

ISSUES AND NEEDS: Further testing of non-fossil materials and control devices is recommended in order to analyze emissions and set emission limits. A definition of non-hazardous solid waste is needed. The level of solid waste materials that trigger regulation under Section 129 needs to be determined. Further analysis the boilers and their control equipment in this subcategory is needed to determine if more refined subcategories are necessary.

OTHER COMMENTS: None.

ATTACHMENT III

Preliminary Subcategories and MACT Floor Determination for Gas, Distillate Oil and Residual Oil Fired Boilers

Industrial Combustion Coordinated Rulemaking
Federal Advisory Committee

September 16, 1998

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EXECUTIVE SUMMARY

MACT Floor Recommendations

Based on the data reviewed and the assumptions identified below, the ICCR Coordinating Committee is unable to identify a MACT floor, at this time, for oil and/or gas fired boilers. No best performing 12 percent of existing sources could be identified by reviewing the following information:

- Existing add-on controls that may reduce HAPs
- Existing emissions data, air regulations, and air permit limitations for HAPs

In addition, the ICCR Coordinating Committee is unable to forward any recommendations, at this time, on whether:

- good combustion practice (GCP) should be considered as a MACT Floor, or
- gaseous fuel derived from the processing of crude oil, petroleum or petrochemicals should be categorized with natural gas.

The Committee recommends that further evaluation of both the emission database and inventory database is needed to determine MACT floors for solid fossil fuel (coal) fired boilers. At this time, the Committee is unable to offer any MACT floor recommendation regarding the MACT floor for solid fossil fuel (coal) fired boilers.

Fossil Fuel Fired Boiler Subcategories

The ICCR Coordinating Committee recommends the following preliminary subcategories for fossil fuel fired boilers:

- Natural Gas (Includes wellhead gas, pipeline gas, LPG)
- Oils
  - Unheated or Distillate Oils
  - Heated or Residual Oils
- Coal (Solid Fossil Fuel)
- <u>Fluidized Bed Boilers</u> subcategorized further as:
  - Anthracite, Bituminous, Subbituminous, Lignite, Petroleum Coke
- <u>Mass Fired / Stoker Boilers</u> subcategorized further as:
  - Anthracite, Bituminous, Subbituminous, Lignite

Pulverized / Cyclone Boilers subcategorized further as:

- Anthracite, Bituminous, Subbituminous, Lignite, Petroleum Coke

The Coordinating Committee recognizes that the final subcategories for any MACT standards established for existing fossil fuels may be different than those established for the purposes of the preliminary MACT floor determination since other information and data reviews may occur between now and the final rule.

Rationale for Fossil Fuel Subcategories

Natural Gas Boilers

Basically Natural Gas Boilers (including wellhead gas, pipeline gas, LPG, and gaseous fuels derived from processing of crude oil, petroleum or petrochemicals) have similar burner design. Whether fire tube or water tube boilers, combustion characteristics for HAPs are assumed to be defined by the fuel rather than the burner.

Oil Fired Boilers

Like gas fired boilers, the preponderance of oil fired boilers have similarly designed burners. In general they atomize the fuel into the firing chamber by means of steam, air or a mechanical device. Oil type may, however, influence HAPs emissions, therefore, oil fired systems were divided into two subcategories: distillate (unheated) oil and residual (heated) oil.

Coal Fired Boilers

For the solid fossil fuel fired boilers two main factors were considered for the subcategories. These were basic boiler design and fuel type. The boiler designs were split into three basic firing types: pulverized/cyclone, mass fired, and fluidized bed. Each of these firing types could have an effect on HAP formation due to the differences in boiler and fuel feed design. After considering the firing type, the fuel type must be considered. The ASTM standard fuel definitions were used: anthracite, bituminous, subbituminous, and lignite. Petroleum coke was also considered as a fuel type. The fuel type also plays a key role in boiler design that could effect HAP formation and emissions.

Rationale for MACT Floor Determination

In order to identify the best performing group of sources and determine the MACT floors, the ICCR Coordinating Committee reviewed the following available information related to control devices and HAPs emissions for existing boilers:

- Existing add-on controls that may reduce HAPs,
- Existing good combustion practices that may reduce HAPs,
- Existing emissions data, and

- Existing air regulations, air permits and RACT/BACT/LAER databases for HAPs limitations.

The EPA ICCR Inventory Database version 3.0 was reviewed to assess the prevalence of existing add-on controls for gas and oil fired systems. The average of the best performing 12 percent of existing boilers in a subcategory could be estimated by first assessing whether at least 6 percent of the boilers in a subcategory had add-on controls. Using this approach, less than 6 percent of the gas fired and oil (distillate and residual) fired boilers in the database have add-on controls. This approach, therefore, fails to identify a best performing group of boilers which could serve to define the MACT floor.

The ICCR Coordinating Committee also reviewed Good Combustion Practice (GCP) for gas and oil fired boiler systems. Issues like air/fuel ratios and maintenance practices were studied. However, the Committee is unable to forward any recommendation at this time on whether good combustion practices could identify a best performing group of boilers which could serve to define a MACT floor.

Emission data were also reviewed to determine if emission data could identify a MACT floor. The emissions database for boilers, state permit limits, state regulation limits and the RACT/BACT/LAER databases were reviewed. Based on the information in these databases the ICCR Coordinating Committee concludes there is insufficient information to identify a MACT floor based on this approach.

1.0 INTRODUCTION

Below is a description and discussion of the following topics that led to the ICCR Coordinating Committee's recommendations on subcategorization and MACT floor:

- Subcategorization methodology and rationale
- Review of the EPA Boiler Inventory Database (V 3.0), state regulation and permit databases
- Review of the Emissions Database and state regulation and permit databases
- Review of Good Combustion Practices

2.0 PRELIMINARY SUBCATEGORIES FOR FOSSIL FUEL BOILERS

2.1. Key Definitions

There are several key definitions to be considered when beginning to subcategorize fossil fired boilers.

2.1.1 Boiler

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting useful thermal energy in the form of hot water, saturated steam or superheated steam. The principal components of a boiler are a burner, a firebox, a heat exchanger, and a means of creating and directing gas flow through the unit. A boiler's combustion chamber and primary energy recovery section(s) must be of integral design (i.e., the combustion chamber and the primary energy recovery section(s), such as a waterwall and superheaters, must be physically formed into one manufactured or unit assembled unit). (A unit in which the combustion chamber and the primary energy recovery section(s) are joined only by ducts or connections carrying flue gas is not integrally designed; however secondary energy recovery equipment (such as economizers or air preheaters) need not be physically formed into the same unit as the combustion chamber and the primary energy recovery section.) Only stand-alone boilers are covered by this definition; waste heat boilers, which are associated with stationary gas turbines or engines, are excluded.

2.1.2 Natural gas

The natural gas category includes:

- <u>Standard Definition of Natural Gas</u>: The definition for Natural Gas was taken from the NSPS Rules in 40 CFR 60.41b: a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American

Society for Testing and Materials in ASTM D1835-82, "Standard Specification for Liquid Petroleum Gases". For all practical purposes, natural gas includes wellhead gas which is gas straight from the ground containing principally methane, hydrogen, carbon and oxygen.

- Liquid Petroleum Gas (LPG): LPG is propane and/or butane often with small amounts of propylene and butylene sold as a pressurized liquid. LPG is also used by boilers for ignition fuel and as a standby fuel. For purposes of the MACT Floor determination, LPG is included with natural gas as given in the definition above.

The ICCR Coordinating Committee is unable to forward a recomendation at this time on adding gaseous fuels derived from processing of crude oil, petroleum or petrochemicals to the definition of natural gas. The Petroleum Environmental Research Forum Project 92-19 (PERF data) found no significant difference in air toxic emissions between burning natural gas, as defined above, and these process derived gaseous fuels. Enclosed in Appendix 1 there is a paper entitled "Rationale for Broad Definition of Gaseous Fuels" which supports the argument of incorporating gaseous fuels derived from processing of crude oil, petroleum or petrochemicals into the definition of natural gas. However, at this time, because of not being able to completely review and digest the information, the ICCR Coordinating Committee is unable to forward a recommendation in this area.

2.1.3 Oils

Oils can be divided into two categories:

- Distillate Oil (also called unheated oil): Fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Material in ASTM D396-78, Standard Specifications for Fuel Oil. (40 CFR 60.41b)

- Residual Oil (also called heated oil): Crude oil, and all fuel oil numbers 4,5, and 6 as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils. (40 CFR 60.41b)

2.1.4 Coal

The coal definition is the same as that from 40 CFR 60.41b (NSPS Subpart Db) – Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank, coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal; coal-oil mixtures are also included in this definition.

2.2 Subcategorization

The ICCR Coordinating Committee recommends the use of subcategories for fossil fuel fired boilers which incorporate factors that may affect the HAP emissions from those units and/or the viability of control techniques that may reduce HAP emissions from those units. The Coordinating Committee recommends the use of fuel type and firing method as key factors which may affect HAP emissions and the viability of controls.

Gas, oil and coal were initially divided into categories due to the nature of constituents making up the fuel type and their method of handling. For instance gas is primarily methane, hydrogen, carbon and oxygen. However, coal may contain metals and more complex hydrocarbons. Coal is burned in a different manner than either gas or oils.

2.2.1 Gas Fired Boilers

Gas fired boilers are considered a single subcategory for several reasons. The first is based on the overall emissions from those types of boilers. The emissions on all types of gas fired boilers, although variable, were generally very low. Second, the controls on boilers generally are not designed to control HAP emissions. Third and perhaps most important is that the burner design on gas fired boilers is essentially the same for various types of gas fired boilers. It consists of an air and gas mixing system. The burner is designed to guarantee adequate mixing for good stoichiometric combustion.

2.2.2 Distillate Oil Fired Boilers

Distillate oil boilers are also considered a single subcategory for essentially the same reasons as gas fired systems. The oil is atomized in the burner in several ways (air, steam or mechanical). The purpose of atomization, no matter what the method, is to better mix the fuel with the air. It was assumed, like gas, that distillate oil because of the similarity of the fuel mixing burners and the effectiveness of the burners, that combustion characteristics and therefore the HAPs emissions should not be appreciably noticeable between boiler types.

2.2.3 Residual Oil Fired Boilers

All residual oils or heavy oils (No. 4 and above) are generally heated prior to introduction in to the burner. Residual oils, like distillate oils use various atomization methods for injection of the fuel into the firing chamber. Because of similar firing designs among oil burners, residual oil boilers was also considered a single category.

2.2.4 Coal Fired Boilers

2.2.4.1 Solid Fossil Fuels (Coal). The ASTM fuel types serve to further subcategorize coal fired boilers. Petroleum coke was also included as a fuel type. Fuel types vary by their carbon content and other factors like moisture content, ash content, and BTU content to name a few. All of these factors effect boiler design and can affect HAP formation and emissions.

ASTM Standard D388 - 77 is entitled “Standard Classification of Coals by Rank.” The main ranks of coal in this standard are anthracite, bituminous, subbituminous, and lignite. Each of these major ranks is broken down into at least two sub-ranks. The Committee recommends no need to break the ranks into the sub-ranks for subcategories. Fuels are ranked by carbon content if the carbon content is greater that 69 percent and by BTU content for all other fuels. Carbon content is generally inversely proportional to volatile content. This factor plays a key role in boiler size (e.g., larger for higher volatility) and configuration.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 6,000 Btu per pound (Btu/lb) on a dry basis.

Petroleum Coke is a carbonaceous solid produced from coal, petroleum, or other materials by thermal decomposition.

Many other factors affect boiler design and vary with fuel type. These include ash content and ash characteristics, and moisture content. All of these factors are taken into account when sizing a boiler and designing the heat transfer surfaces. As the design changes to accommodate the differences in the fuel, many things in the boiler change including the temperature profile which could effect HAP formation and emission rates. The boiler designs established for subcategories are the following: pulverized coal/cyclone, mass fired, fluidized bed.

<u>2.2.4.2 Solid Fuel Boiler Types</u>. The Committee also recommends further subcategorizing this coal subcategory by boiler types. Three main boiler types are appropriate for subcategorization. The types are fluidized bed boilers, mass feed or stoker boilers, and pulverized coal or cyclone boilers. Each of these boilers has a unique firing system that could result in different HAP emissions.

Many factors must be considered during boiler design. One of the main factors is where and how the fuel is introduced into the furnace. This led to the recommendation to subcategorize by boiler types. The types are fluidized bed boilers, mass fired/stoker boilers, and pulverized/cyclone boilers.

Each boiler type has a different firing system. Pulverized and cyclone boilers fire the fuel in suspension while in mass fired boilers some portion of the combustion takes place on the furnace floor on a grate. The fluidized bed boilers burn fuel in an aerated mass. Each of these firing types leads to different temperatures of combustion and boiler temperature profiles that can result in different HAP formation and emission rates.

<u>Pulverized Coal/Cyclone</u>

Pulverized coal boilers burn coal in suspension by pulverizing the coal and injecting it into the boiler with a transport air stream. In general, a low percentage of ash drops out as bottom ash (approximately 20 percent), with the remainder passing through the boiler as flyash, dropping out in hoppers or particulate collection devices. Pulverized coal fired boilers can be dry bottom or wet bottom. Wet bottom boilers operate at a higher furnace temperature and use coal with properties that allow a portion of ash to be removed from the furnace in the molten state. Dry bottom boilers operate at a lower temperature and use coal with properties, which do not create molten slag in the furnace. While there could be differences in HAP emissions from dry bottom vs wet bottom boilers, there is not adequate data on which to differentiate between those designs for purposes of subcategorization.

Cyclone boilers burn crushed coal in cyclones prior to entering the boiler furnace. The cyclones operate at a high temperature, which allows a significant quantity of ash to be removed in the molten state.

In general, HAP emission rates are believed to be similar for pulverized coal and cyclone boilers.

Mass Fired

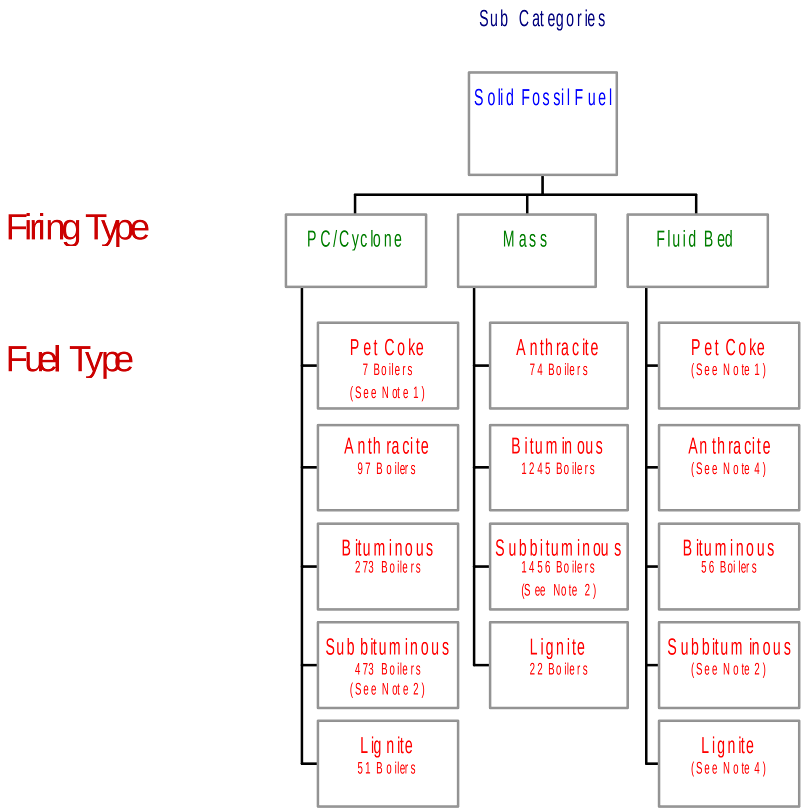
Mass fired boilers include mass feed stokers, spreader stokers, and underfeed stokers. These types of boilers are characterized by the use of larger sized coal (about 2x0 top size) wherein most of the coal is burned on the grate. This feature results in most of the coal ash being removed as bottom ash (at least 80 percent), with the remainder passing through the furnace as flyash, dropping out in hoppers or particulate collection devices. Some stoker-fired boilers also reinject cinders or flyash into the furnace in order to reduce unburned carbon losses. Excess air levels in general are higher for mass fired boilers vs pulverized coal/cyclone units due to the greater difficulty in obtaining proper fuel/air mixing with mass fired units.

Fluidized Bed

Fluidized bed boilers operate with either a bubbling bed or circulating bed. In both cases, the upward velocity of air through the bed causes a suspension of the fuel and inert matter. Circulating fluid bed units operate with a high furnace velocity, which entrains particulates and allows recirculation back into the bed for increased carbon burnout.

An important design parameter is the type of fuel in combination with the boiler type. As an example, a bituminous stoker is designed much differently than a pulverized bituminous unit. The result could be different HAP emissions from the same fuel. All of the above reasons led to the recommendation to subcategorize based on firing type in combination with fuel type. Figure 1 illustrates the solid fossil fuel (coal) fired boiler subcategories.

Figure 1: Coal Fired Subcategories



Note 1 34 Petroleum Coke Boilers were identified in the Inventory Database with no boiler type

Note 2 33 Subbituminous Boilers were identified in the Inventory Database with no boiler type

Note 3 404 Boilers were identified in the Inventory Database with no boiler type or fuel type

Note 4 No Boilers were identified in the Inventory Database for these types; These could exist

3.0 APPROACH AND RATIONALE FOR MACT FLOORS

3.1 General Approach to MACT Floor Analysis

Several assumptions need to be identified, as follows:

- This is a preliminary MACT Floor recommendation; testing has not been performed and the data are still being analyzed.
- The categories are based on fuel type (gas, liquid and solid) as described above.
- The data examined is the EPA Boiler Inventory Database Version 3.0. Specifically, the data that were reviewed were from the dataset that specified control/abatement information or indicated no control. That is, all of those units on the database that did not specify control information were left out of this evaluation.
- The requirements of Section 112 (d) of the 1990 CAA specify that for 30 sources or more in a category, the MACT floor is the average emission limitation achieved by the *best performing 12 percent* of existing sources in the category (*for which the administrator has emissions information).* The average of the "best performing 12 percent" would be the top 6 percent of the boilers. Anything below 6 percent would not be considered.
- The units considered here burn only fossil fuels.
- The emissions database, state air regulations and permits information along with the RACT/BACT/LAER information were also reviewed to determine if there was enough information to determine a MACT floor.
- The databases were reviewed from a GCP and Pollution Prevention (P2) perspective to determine if a MACT floor based on GCP and/or P2 could be identified.

3.2 Available Data and Information for the MACT Floor

3.2.1 ICCR Boiler Population Database

3.2.1.1 Gas. Version 3 of the EPA Boiler Inventory Database contained a total of 42,582 gas fired boilers. In the analysis of those boilers only 18,321 boilers had control or abatement information. The rest of the boilers did not specify any control information. There were only 177 boilers or about 0.97 percent that indicated controls which might impact HAP emissions.

Because this was well below the level of 6 percent limit which could serve to identify a MACT floor, the ICCR Coordinating Committee was unable to identify a MACT floor using this approach for Gas Fired Boilers.

3.2.1.2 Distillate Oil. In Version 3 of the EPA Inventory Boiler Database there were 6604 boilers in the distillate (unheated) oil category. Of that, only 2623 boilers had control or abatement information or indicated that there were no controls. Seventy (70) boilers or 2.68 percent of the boilers had controls of some sort which might impact HAPs emissions.

Because this was well below the level of 6 percent which could serve to identify a MACT floor, the ICCR Coordinating Committee was unable to identify a MACT floor using this approach for Distillate Oil Fired Boilers.

3.2.1.3 Residual Oil. Version 3 of the EPA Boiler Inventory Database has 7945 residual or heated oil boilers. Of those, 4810 boilers had control or abatement information. Only 264 boilers or 5.50 percent had controls which might impact HAPs emissions.

Again, this was below the level of 6 percent which could serve to identify a MACT floor, so the ICCR Coordinating Committee was unable to identify a MACT floor using this approach.

3.2.1.4 Coal. At this time, the ICCR Coordinating Committee is unable to offer any recommendations regarding the MACT floor for coal fired boilers.

3.2.2 ICCR Boiler Emissions Database

The ICCR Coordinating Committee reviewed the ICCR Emissions Database to determine if the emissions data from gas- and oil-fired boilers could be used to identify a MACT floor. Based on a review of the available emissions information, the Committee recommends that the existing emissions data are inadequate to identify a best performing group of existing boilers and hence identify a MACT floor for any boiler subcategories.

3.2.2.1 Gas Emissions Data. The ICCR Emissions Database for boilers fired with gas includes over 20 air emission test reports for HAPs. Gas-fired boilers in the database range in size from 2 MMBtu/hr to 7,500 MMBtu/hr heat input, or from less than 1 MW to 750 MW. The test reports represent tests conducted on 50+ boilers (as compared to over 40,000 gas-fired boilers in the ICCR Inventory Database). The database includes data from few boilers in the industrial sector (e.g., oil and refining), but mostly from very large boilers in the utility sector. A large majority of the source tests were conducted in the State of California as part of the AB2588 (Air Toxics "Hot Spots" Information Assessment Act of 1987) program.

The HAP emissions information in the ICCR Emissions Database for gas-fired boilers is very limited. This information may not be representative of emissions of gas-fired boilers that are in the commercial/institutional/industrial boilers source category due to differences in design, control equipment, and operational practices. There is no data to evaluate control efficiencies.

The HAP emission levels for gas-fired boilers in the ICCR Emissions Database are variable. For example, formaldehyde and benzene levels for gas-fired boilers cover two-to-three orders of magnitude. This is consistent with the recent American Petroleum Institute study titled "Emissions Variability on Boilers"(Appendix 2) that discusses this variability. The study states that, "The variability in the ICCR emissions database arises from the inherent variability in the combustion and measurement processes. This variability is magnified in the field due to differences in sampling and analytical methods, to differences in design, operational parameters, and location, as well as the level of data quality assurance screening."

3.2.2.2 Oil Emissions Data. The ICCR Emissions Database for oil fired boilers was reviewed to determine if the emissions data could be used to identify a MACT floor. Based on a review of this information, the ICCR Coordinating Committee recommends that the existing emissions data are inadequate to identify a best performing group of existing boilers and hence to identify a MACT floor.

The actual test reports in the database were not completely reviewed, but review of the emissions database provides the following insights. Many "Fuel Oil" fuel type units, which are generally interpreted as distillate oil fired units, are fired with residual oil as indicated by the fuel data information. Some of the boilers are identified as being originally designed for coal firing and tested while firing oil. This leads to incorrect interpretation of controls which are applied to oil fired boilers. In some cases, it is noted that where particulate collection devices are installed, they were not in operation during the emission tests. Other tests did not indicate whether this was the case or not. Most of the emissions test data is from electric utility units and not from industrial boilers. While HAP emissions from utility units could be similar to industrial units, that is not an indication of emissions from industrial boilers. Much critical data is not listed in the database or indicated as "Not Provided."

In addition, there are orders of magnitude differences in HAP emission rates from different runs and tests on the same unit with no other apparent differences in operation or other data to indicate a cause for the variation. This leads to a conclusion of inherent variability in HAP emission rates and an inability to identify a best performing group of boilers to define a MACT floor. Some test data is from a very small boiler with uncharacteristically high excess air levels and is not indicative of typical industrial boilers. Some HAP emissions are truly a function of the fuel properties; no fuel data is provided. There is conflicting information in the database with no explanation, e.g., "No Equipment" vs the comment information.

3.2.2.3 Coal Emissions Data. Version 3 of the Emissions Database contains information from 255 sites or conditions for coal fired boilers. Some boilers were tested under different conditions, like before and after air pollution control devices. The 255 tests resulted in 6550 stack tests for individual parameters. In other words, about 25 parameters were identified per boiler/condition.

The database is mostly from the work done in the report to Congress entitled "Study of Hazardous Air Pollutant Emissions from Electric Steam Generating Units - Final Report to Congress". This study was done for larger utility sources, but the data should be comparable to industrial coal boilers. Other database sources were from AP42 information and from STIRS.

The database is difficult to interpret due to the number of control device combinations. In order for the database to be used for rulemaking, the subcategories must be defined and then the database must be sorted by the subcategories and then by control device. These steps will be tedious since much of the information in the database fields do not provide enough information to easily sort items such as control device.

3.2.3 State Air Regulations and Air Permit Limits for HAPs

In reviewing State air regulations and air permit limits, the ICCR Coordinating Committee limited the review to specific limits on HAPs only. Although some States regulate air emissions of volatile organic compounds (VOCs) from existing boilers, and some HAPs are VOCs, control of VOCs does not necessarily control HAPs. Similarly, although some States regulate air emissions of particulate matter (PM) from existing oil-fired boilers, and some HAPs are PM, the control of PM does not necessarily control HAPs. Therefore, the ICCR Coordinating Committee recommends that VOC and PM emission limitations are insufficient, at this time, to be used as the basis for identifying a best performing group of boilers and hence a MACT floor.

3.2.3.1 State Regulations. Copies of State regulations for boilers were reviewed. This review was unable to identify any state air emission regulations that establish specific emission limitations for HAP emissions from natural gas fired or fuel oil fired boilers. Time did not allow a sufficient review of coal fired boilers.

3.2.3.2 RACT/BACT/LAER Databases. The RACT/BACT/LAER Clearinghouse contains information from air permits submitted by most of the state and local air pollution control programs in the United States. Emissions limits for boilers were reviewed by downloading all available databases (historical, transient, and current) of the RACT/BACT/LAER Clearinghouse. The historical, transient, and current RACT/BACT/LAER databases were searched individually for state air permit limitations for boilers. Information was obtained on 15 fuel oil fired boilers out of 14,510 total in the inventory database. HAP permit limits were reported for at least one of the following pollutants: Arsenic, Beryllium, Bromine, Cadmium, Chromium, Copper, Formaldehyde, Lead, Manganese, Mercury, Nickel, Polycyclic Organic Materials (POMs), Selenium, and Vanadium. No HAP permit limits were identified for natural gas fired boilers.

3.2.3.3 Permit Limits. Version 3 of the EPA ICCR Inventory Database includes HAPs air permit limits for 17 gas fired boilers, out of 42,582 total gas fired boilers, and no fuel oil fired boilers out of 14,510 total fuel oil fired boilers. HAP permit limits are reported for at least one of the following pollutants: Benzene, Chlorine, Ethylbenzene, Formaldehyde, Hydrogen chloride, Toluene, and Vinyl chloride.

Permit limits were identified for boilers in both the RACT/BACT/LAER database and the inventory database. The ICCR Coordinating Committee recommends, however, that these permit limits not be used to identify a MACT floor since:

1. There is insufficient information in the EPA ICCR Inventory Database to properly subcategorize the units.

2. It is unclear whether the permit limitations are based on emissions testing or on the use of emission factors, such as AP-42.

3. The 15 fuel oil-fired boilers and 17 natural gas-fired boilers represent less than 0.2 percent of fuel oil-fired boilers and less than 0.05 percent of the natural gas-fired boilers in the ICCR inventory database.

3.3 Emission Control Techniques

The ICCR Coordinating Committee assessed possible emissions control techniques which could impact HAP emissions from gas and oil fired boilers.

3.3.1 Gas Fired Boilers

The inventory database indicates a low percentage of gaseous fired boilers equipped with control devices which could reduce mercury, inorganic HAP, and metal emissions. However, that data has not been verified at this time, and it is believed that those indicated boilers are designed for some fuel other than natural gas. There is no knowledge of situations where control devices are used on gas fired boilers. Based on the data reviewed, the ICCR Coordinating Committee recommends that the use of control devices on gas fired boilers not be used to identify a MACT floor.

3.3.2 Distillate Oil Fired Boilers

The inventory database for distillate oil fired boilers was reviewed and there are very few control devices which could reduce mercury, inorganic HAP, and metal emissions from distillate oil fired boilers. It is believed that some, if not all of those indicated control devices are associated with another fuel rather than distillate oil. (For example, 0.46 percent of boilers with ESP's, 0.69 percent with cyclones, 0.04 percent with gas absorbers, 0.04 percent with activated carbon adsorption). Based on the data reviewed, the ICCR Coordinating Committee recommends that the use of control devices on distillate oil fired boilers not be used to identify a MACT floor.

3.3.3 Residual Oil Fired Boilers

The inventory database indicates a low percentage of residual oil fired boilers equipped with control devices which could reduce mercury, inorganic HAP, and metal emissions. However, that data has not been verified at this time, and it is believed that many of those indicated units are designed for some fuel other than residual oil. There are some residual oil fired boilers which have SO_2 scrubbers installed, and SO_2 scrubbers provide some HAP emission reductions. However, they are a small percentage of the total (0.69 percent) prior to verification of the database. Based on the data reviewed, the ICCR Coordinating Committee recommends that the use of control devices on residual oil fired boilers not be used to identify a MACT floor.

3.4 Good Combustion Practices (GCP)

The ICCR Coordinating Committee assessed GCP for gas and oil fired boilers by (1) researching and reviewing possible GCP for the purpose of HAP reduction from boilers and (2) assessing the prevalence of those practices by reviewing information available in the EPA ICCR Inventory Database and information from state air permitting authorities.

Based on the information review thus far, the Committee is unable to forward a recommendation on the use of GCP to identify a MACT Floor for existing gas or oil fired boilers.

3.4.1 Fuel/Air Ratio Control.

Controlling fuel/air ratio by various methods is assumed to provide possible minor reductions in organic HAPs. Some gas fuel fired boilers were identified to control fuel/air ratios in the Inventory Database, but only a very low number (0.43 percent). Similarly, some oil fired boilers were identified to have GCP in the Inventory Database, but only a very low number (0.99 percent for distillate oil or 0.34 percent for residual oil). There were no data in the emissions database which could be used to quantify any HAP emissions reduction associated with this control. The PERF test report found no significant difference in HAP emissions with any additional fuel/air controls over those routinely employed by boilers. All existing boilers must use fuel/air ratio controls of some sort to comply with existing safety and air permit requirements. Based on the information review thus far and the above discussion, the ICCR Coordinating Committee is unable to forward any recommendations at this time on the use of fuel/air ratio control to identify a MACT floor.

3.4.2 Maintenance Practices

Poor maintenance practices of boilers could possibly lead to deterioration of unit efficiency and incomplete fuel combustion, which could lead to increased HAP emissions. However, economics and existing permit requirements force attention to proper maintenance. Maintenance practices, however, can vary significantly depending on the design and operating characteristics of individual boilers. There are also no data available in the inventory or emissions database upon which to base any quantification of HAP emissions impact based on levels of maintenance. Based on the information review thus far and the above discussion, the ICCR Coordinating Committee is unable to forward any recommendations at this time on the use of maintenance practices to identify a MACT floor.

3.4.3 State Regulations

Data from state regulations relative to practices that could be considered GCP were reviewed. However, at this point, it is not possible to determine the number of boilers in the inventory database which are required to meet these requirements, since the State requirements are directed at specific locations, heat input capacities, and other limiting criteria. Additional efforts would be needed to draw any conclusions from this data.

However, some observations could be drawn from the data. First, the boilers subject to these practices are doing so as part of ozone nonattainment programs targeting NOx emission reductions. Second, there are boiler size applicability limits to many of the practice requirements, and that would greatly influence the number of boilers impacted. There is also no information relative to the HAP emission impact of any of the practices. Based on the information review thus far, the ICCR Coordinating Committee is unable to forward any recommendations on the use of GCP in State regulations to identify a MACT floor.

3.5 Pollution Prevention (P2)

Boiler efficiency could be related to HAP emissions on the basis of decreased fuel input requirements in order to meet output demands. However, it is extremely difficult to identify a MACT Floor which could include consideration of efficiency in any way. The inherent efficiency of every boiler is unique, and the ability to influence that efficiency is limited by many technical, economic, and operational considerations. The inherent boiler efficiency varies as a function of boiler load and many other conditions. Therefore, while this could be further considered, based on available information, the ICCR Coordinating Committee is unable to forward any recommendations based on the use of boiler efficiency to identify a MACT floor.

APPENDIX 1

Rationale for Broad Definition of Gaseous Fuels

Rationale for Broad Definition of Gaseous Fuels

Background

Emissions data on HAPs and criteria pollutants originated from several sources, and have gone through several stages of screening and assessment. For gas-fired external combustion devices (i.e. Boilers and Process Heaters) three primary sources were utilized.

First, source test results collected under the California Air Toxics "Hot Spots" Inventory and Assessment Act (AB2588) have been compiled and quality reviewed in a joint effort by the Western States Petroleum Association (WSPA), the California Air Resources Board (CARB), and the American Petroleum Institute (API). The results of this investigation are compiled in the 3-volume Draft Report titled "Development of Toxics Emission Factors for Petroleum Industrial Combustion Sources" (D. W. Hansell and G. C. England, EER Corporation, September 1997). It was provided to the US EPA in October 1997. The validation and verification processes used to quality assure these data makes this the most reliable and comprehensive compilation of field emission source test data for petroleum industry combustion sources. The final report was provided to EPA in September 1998.

The second source of emissions test data came from the Petroleum Environmental Research Forum (PERF) 92-19 "Toxic Combustion Byproducts" project. In 1992 PERF initiated a Cooperative Research and Development Agreement (CRADA) with the U.S. Department of Energy, and with EPA participation, performed an experimental and fundamental investigation of chemical and physical mechanisms governing organic HAP formation, destruction, and emissions. These tests on full-scale burners were performed at the Sandia National Laboratories/Livermore. This program produced data of very high quality that shed light on many of the key questions surrounding the field data. The results of this project are summarized in a paper titled "Organic Hazardous Air Pollutant Emissions from Gas-Fired Boilers and Process Heaters" (G.C. England and D.W.Hansell, EER Corporation, July 1997). The PERF 92-19 CRADA Final Report is, "The Origin and Fate of Toxic Combustion Byproducts in Refinery Heaters: Research to Enable Efficient Compliance with the Clean Air Act" (August 5, 1997).

Lastly, the ICCR Emissions Database, V.2, provides a compilation of emissions test data made available from existing electronic databases such as STIRS, and other information from state and local agencies. Emissions information collected from the EPA Section 114 ICR survey was also added to this database.

Conclusions

Based on the discussion above and the references cited therein:

HAP emissions from all gas-fired sources are generally very low, but exhibit inherent variability associated with process fluctuations and sampling and analysis uncertainties.

The PERF data referenced above demonstrate that HAP emissions from typical industry gas fired burners, under a variety of operating conditions are all very low, at or near the detection limits of the best measurement methods. In addition, field source test data, such as the WSPA/API database indicate that annual total HAP emissions from operating gas-fired heaters and boilers are well below the major source definition.

HAP emissions from devices fired by either natural gas or petroleum processing derived gas are similar, on a Btu basis.

The controlled laboratory testing (PERF study) and the WSPA/API field test data demonstrate that emissions factors derived independently for different gaseous fuels are indistinguishable, when measurement uncertainty and process variability are taken into account (Figures 1). The emission factor derivation process accounts for the different heat content of the variety of the gases used in practice, and which like natural gas, consist primarily of hydrocarbons mixtures.

HAP emissions from gas-fired boilers and process heaters are equivalent.

Design practices are such that the same burner types are used for constructing both gas-fired process heaters and boilers. In addition, the field emissions data for boilers and process heaters, fired by a variety of gaseous and liquid fuels, was shown to be similar (Figure 2). The data demonstrate that emissions from boilers or process heaters vary by size (heat input) but are otherwise expected to be equivalent.

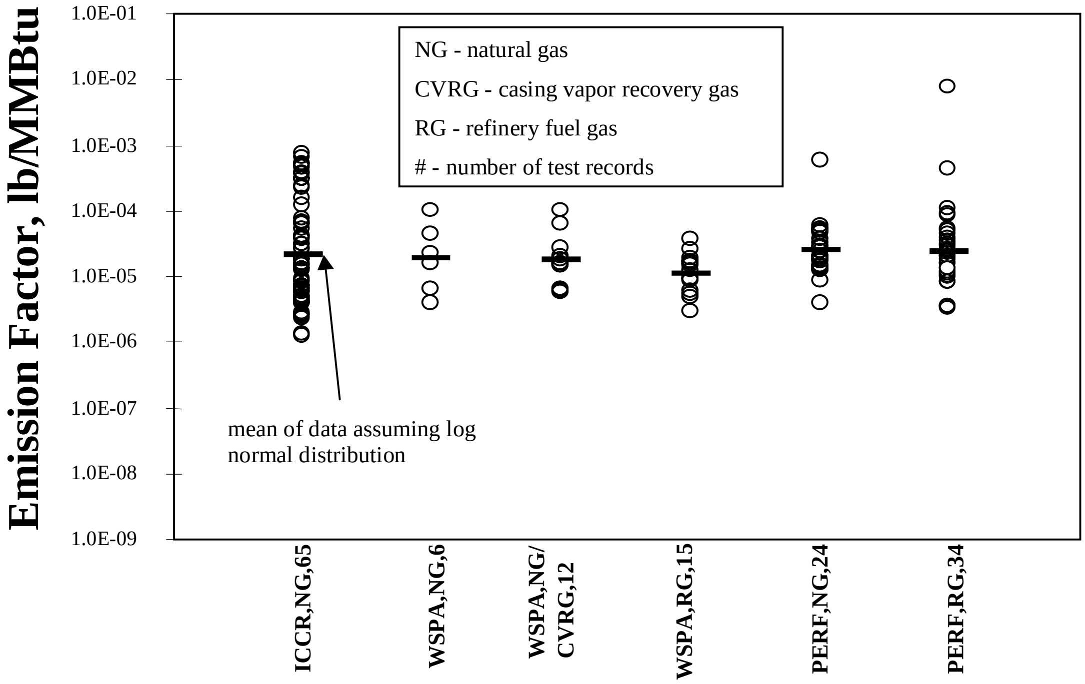
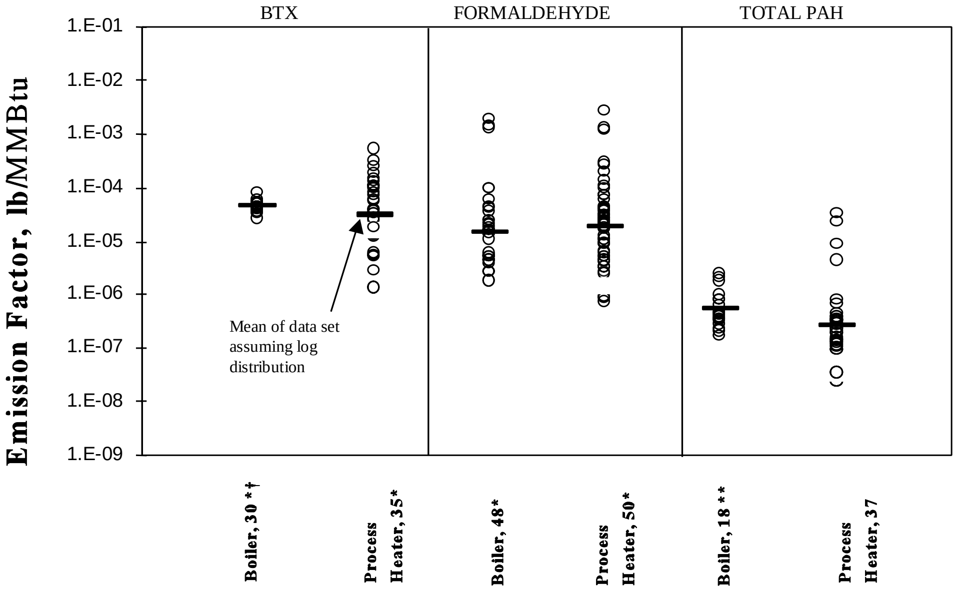


Figure 1. Formaldehyde emissions as a function of fuel type for gas fuel fired boilers (ICCR, WSPA, and PERF data).



* Includes crude, FO #6, and gaseous fuel (primarily gas)

** Includes FO #6 and gaseous fuel (primarily gas)

† Number following label = number of test records

Figure 2. Comparison of HAP emissions data for Boilers and Process Heaters (WSPA)

APPENDIX 2

Emissions Variability From Boilers

Emissions Variability From Boilers

Considerable variability is observed in the reported emissions of HAPs from similar sources firing similar fuels under similar operating conditions. This level of variability is not uncommon in databases of this type and is to be expected when searching for trace emissions at the limits of detection. The variability in the ICCR emissions database arises from the inherent variability in the combustion and measurement processes. This variability is magnified in the field due to differences in sampling and analytical methods, to differences in design, operational parameters, and location, as well as the level of data quality assurance screening.

When analyzing the boiler emissions information in the EPA ICCR emissions database, there is considerable variability in the reported emissions of hazardous air pollutants from similar sources firing similar fuels under similar operating conditions. When looking at any process, there is a natural variability that is inherent to both the process and the device used to measure the process. The vast majority of this variability is most likely due to sampling and analytical errors. Some small portion of the variability may be due to minor differences in the design, operation, and geographic location of the combustion devices.

An instructive demonstration of this inherent variability can be found in the PERF 92-19 study. As shown in Figure 2-1, variability of up to two orders of magnitude can exist even in situations where the combustion device, the measurement techniques, and the operating parameters are highly standardized. This exceedingly high quality data illustrates what might be called the “irreducible minimum” or “inherent” variability that is unavoidable when searching for trace HAP emissions at the limit of detection of the most sophisticated of sampling and analytical methods.

The PERF HAPs emission data were collected at the Sandia National Laboratory, Livermore, California, Combustion Research Facility’s Burner Engineering Research Laboratory (BERL), a 2.0 MMBtu/hr test facility for full-scale industrial burners. Before and after each of the five different full-scale commercial burner test sequences, “Regulatory Base Case” repetitions were carried out to make sure that nothing in the physical setup had changed in the interim between sequences nor over the period of days required to complete a given test sequence. While this was done primarily to make sure that “the same” system was being tested each time, this procedure of Regulatory Base Case repetition provides the concomitant benefit of demonstrating the irreducible minimum data variability for trace HAPs.

The PERF “Regulatory Base Cases” characterized normal operation at 2 MMBtu/hr at a stoichiometric ratio of 1.25 (*i.e.*, 25 percent excess air) and furnace exit temperature 1600F firing either refinery fuel gas, the “A1” cases, or natural gas, the “A4” cases. The Regulatory Base Case “A1” fuel was a mixture of 16 percent hydrogen in natural gas plus propane to yield 1050 Btu/scf heating value while the Regulatory Base Case “A4” was pure natural gas with the same heating value of 1050 Btu/scf. Thus the Regulatory Base Case fuel mixtures, heating value, burner load, stoichiometric ratio and furnace exit temperature were all duplicated at each repetition as nearly as possible and in strict conformance with the highest EPA QA/QC protocols.

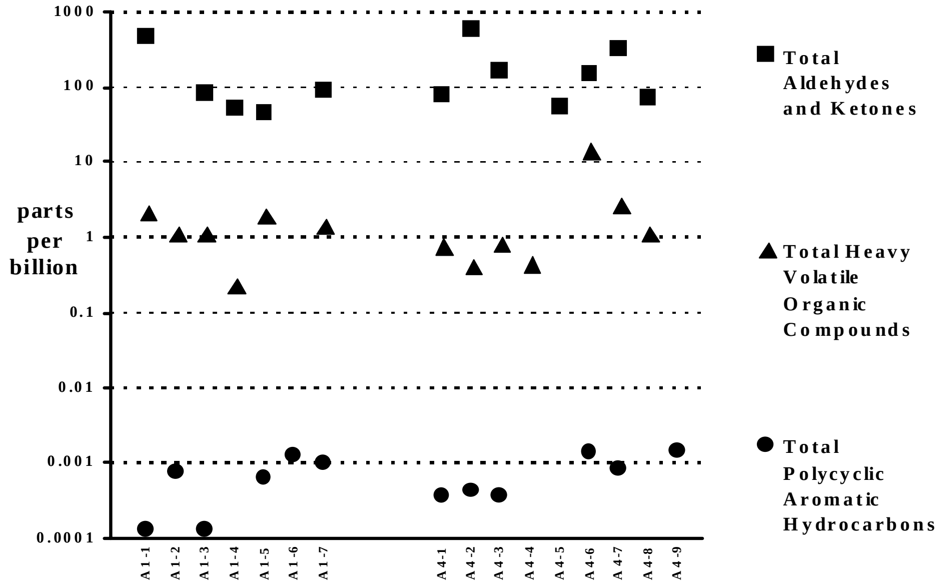


Figure 2-1. PERF 92-19 CRADA Regulatory Base Case Repetitions Illustrate Irreducible Minimum Variability when Searching for Trace Emissions at the Limit of Detection

The PERF 92-19 CRADA's Quality Assurance Project Plan, acknowledged by EPA as one of the best, guaranteed data of regulatory development quality.

As the sampling, analytical, and operating conditions at the BERL were more tightly controlled than would be possible in a field facility, the data from this study provides a benchmark for HAP emissions data variability. For example, one test team, on the same combustion device, using the same sampling and analytical methods conducted at the same laboratories collected all of the data. Yet even under these highly controlled conditions, substantial "inherent" HAP emissions data variability was observed.

This inherent variability that is observed even under the most controlled situations is magnified and added to in the field by many other sources of variability. These sources include differences in sampling and analytical procedures, detection limits, sample volumes, analytical accuracy and precision requirements, lab contamination, data reporting requirements, different sampling contractors, data reduction and data entry errors, etc. Many of these variables are listed in Table 2-1, which shows selected HAPs sampling and analytical procedures, detection limits, and acceptable analytical accuracy and precision requirements. As Table 2-1 illustrates, accuracy errors and imprecisions of up to 50 percent are allowed by many methods. These allowances will contribute to variability in measurements.

Another factor that impacts variability is the level of data quality assurance screening. The U.S. EPA has procedures for addressing low sensitivity, non-detect data and determining and eliminating outliers. For example, the WSPA/API/CARB database has undergone such a screening, which has to some extent lowered the overall variability. The ICCR Emissions Database has not undergone such a screening procedure.

To a much lesser extent, differences in boiler design, in the process operating conditions, and even in the location of combustion systems can contribute to the emissions data variability. For example, operational parameters such as swings in process feed rates and in load changes brought about by interactions with other processes could impact the variability. A combustion system located in a hot, humid climate may be operated differently than a system in a cold, dry climate. Differences can even be expected based upon changes in season i.e. between winter and summer.

Even if each of these many different aspects by themselves contribute only a small percentage of the overall variability, together they can add up to orders-of-magnitude differences in the measured emissions across the population of sources. Lastly, it should be mentioned that a quantitative assessment of the relative contribution of the various factors discussed in the Section is not possible based on the information available in the ICCR databases.

TABLE 2-1. Selected HAPs Sampling and Analytical Procedures and Detection Limits[a]

HAP	Sampling & Analytical Method(s)	Sampling Procedure	Analytical Procedure	Detection Limit (ng/dscm) (1)	Detection Limit (lb/MMBtu) (2)	Analytical Precision (%)	Analytical Accuracy (%)
PAH - Benzo(a)pyrene	CARB 429	Isokinetic with XAD-2 resin	HRGC/HR MS	5	2.7E-09	+/- 50	50-150
PAH - Benzo(a)pyrene	CARB 429	Isokinetic with XAD-2 resin	HRGC/LR MS	100	5.4E-08	+/- 50	50-150
PAH - Benzo(a)pyrene	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	LRGC/LR MS	1,000	5.4E-07	+/- 50	50-150
Formaldehyde		Hot wet extraction	FTIR	120,000	6.8E-05		
Formaldehyde	CARB 430	Non-isokinetic with DNPH	HPLC	10,000	5.4E-06	+/- 10	70-130
Formaldehyde	EPA SW-846 M0011/ EPA SW-	Isokinetic with DNPH	HPLC	800	4.4E-07		
Benzene	EPA SW-846 M0030/ EPA SW-	Non-isokinetic with Tenax	GC/MS	1,000	5.4E-07	+/- 50	50-150
Benzene	EPA Method 18	Non-isokinetic with Tedlar Bag	GC/PID/EC D	160,000	8.8E-05	+/- 5	90-110
Benzene	CARB 410A	Non-isokinetic with Tedlar Bag	GC/PID	11,000	5.8E-06	+/- 5	90-110
Benzene	CARB 410A	Non-isokinetic with Tedlar Bag	GC/FID/PI D	3,200	1.8E-06	+/- 5	90-110
Benzene	EPA SW-846 M0040/EPA TO-	Non-isokinetic with Tedlar Bag	GC/MS	1,600	8.8E-07	+/- 25	70-130
Benzene			FTIR	320,000	1.8E-04		
PCDD/PCDF-2,3,7,8-TCDD	EPA Method 23	Isokinetic with XAD-2 resin	HRGC/HR MS	0.005	2.7E-12		
PCDD/PCDF-2,3,7,8-TCDD	CARB 428	Isokinetic with XAD-2 resin	HRGC/HR MS	0.005	2.7E-12	+/- 30	60 - 140
PCDD/PCDF-2,3,7,8-TCDD	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	HRGC/HR MS	0.05	2.7E-11		
PCDD/PCDF-2,3,7,8-TCDD	EPA SW-846 M0010/ EPA SW-	Isokinetic with XAD-2 resin	HRGC/LR MS	50	2.7E-08		

[a]The analytical procedure is the parameter that can be expected to have a large impact on the emissions variability. This is due to the fact that non-detect data are generally reported as either the full or one-half the detection limit. Thus, units with emissions below detectable levels will have very different reported emissions if they are tested by two methods with different detection limits. For example, the detection limit for the polycyclic aromatic hydrocarbon benzo(a)pyrene is a factor of 200 lower if the sample is analyzed using high resolution gas chromatography (GC)/high resolution mass spectrometry (MS) rather than low resolution GC/low resolution MS. Therefore, if two similar sources are tested for benzo (a) pyrene, one using the high resolution technique and the other using the low resolution technique, and benzo (a) pyrene is not detected

in either sample, the reported emissions will be 200 times higher for the source tested with the low resolution technique even if all other sources of variability are equivalent. Both techniques are valid, however the low-resolution technique is less expensive.

ATTACHMENT IV

HAZARDOUS AIR POLLUTANTS (HAPS) OF INTEREST FOR FOSSIL FUEL FIRED BOILERS

Industrial Combustion Coordinated Rulemaking (ICCR)
Federal Advisory Committee

September 16, 1998

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report identifies a list of Hazardous Air Pollutants (HAPs) of Interest for fossil fuels (gas, distillate oil, residual oil and coal) fired in boilers. The list of HAPs of Concern is really divided into three lists:

- HAPs OF INTEREST recommended for further investigation;
- HAPs recommended FOR FURTHER TESTING; and
- HAPs recommended FOR POTENTIAL REGULATION.

A general protocol was developed to identify the list of HAPs of Interest. The protocol included:

- Reviewing different reference sources to develop a list of HAPs of Initial Concern for each fuel category;
- Compiling known emission rate data from reliable sources for those HAPs of Initial Concern;
- Determining the magnitude of HAPs emissions vented from boilers of 10 million BTU/hr (MM BTU/hr), 100 MM BTU/hr, and 250 MM BTU/hr firing rates;
- Comparing the actual emissions with de minimis limits derived from a very conservative stack model provided by the New Hampshire Dept. of Environmental Services (Air Resources Division);
- Performing a second screening of HAPs of Initial Concern emission rates for a 250 MM BTU/hr boiler. Actual emissions impact was determined using more realistic assumptions for the model boiler. The 250 MM BTU/hr boiler emissions were compared to the second round NHDES model levels, the Florida Ambient reference concentrations, and the BIF Levels (RAC); and
- Developing the final list of HAPs of Interest for fossil fuel fired boilers based on:
  - HAPs that exceeded the models' screening levels
  - HAPs that were considered high toxic risks
  - HAPs that did not have enough data to support a recommendation.

Below is the final List of HAPs of Interest. The HAPs that appear on this list may or may not appear on the list of HAPs for Further Testing or the list of HAPs for Potential Regulation.

Table 1. Gas HAPs of Interest List

Chemical	Chemical
Benzene	Phosphorus
Toluene	Dioxin
Hexane	Cadmium Compounds
POM’s	Chromium Compounds
Formaldehyde	Cobalt Compounds
Nickel	Lead Compounds
Acetaldehyde	Manganese compounds
Dibenzofurans	

Table 2. Distillate Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM’s/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Acetaldehyde	Nickel

Table 3. Residual Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM’s/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Selenium	Nickel
	Phosphorus

Table 4. Coal HAPs of Interest List

Chemical	Chemical
Benzene	
Isophorone	Nickel
Dioxins	Phenol
POMs	Selenium
Hydrochloric Acid	Cyanide
Hydrogen Fluoride	Acrylamide
Acetaldehyde	Acrylonitrile
Acrolein	2-chloro-acetophone
Methyl Iodide	Ethylene Dibromide
Arsenic	Formaldehyde
Beryllium	Hexachlorobenzene
Cadmium	Methyl Chloride
Chromium	N-Nitrosodimethylamine
Lead	1,1,2,2 Tetrachloroethane
Phosphorus	Antimony Compounds
Manganese	Radionuclides
Mercury	Cobalt

I. INTRODUCTION

This report identifies HAPs of Interest for fossil fired boilers (gas, oils and coal). The HAPs list will be broken down into three distinct categories: HAPs of Interest, HAPs for Further Testing and HAPs for Potential Regulation.

A. <u>HAPs of Interest</u>

The <u>HAPs of Interest</u> included those chemicals that needed to be further investigated because they fell into one or more of the categories below:

- above initial screening levels;
- potential of extreme toxicity;
- listed as an urban air toxic; and/or
- HAPs having little or no emission data.

B. <u>HAPs for Further Testing</u>

HAPs that appear on the HAPs of Interest list will then be reviewed to see if they need to be tested. Those that don't have adequate emission data should be further tested. This list will become <u>HAPs for Further Testing</u>.

C. <u>HAPs for Potential Regulation</u>

These are HAPs of Interest that may need to be regulated or controlled. This list of <u>HAPs for Potential Regulation</u> may be longer or shorter than the list of HAPs of Interest or HAPs for Further Testing.

II. DEFINITIONS

A. <u>Natural Gas</u>

The definition for Natural Gas was taken from the NSPS Rules in 40 CFR 60.41b: a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, "Standard Specification for Liquid Petroleum Gases".

For all practical purposes, this included wellhead gas (gas straight from the ground). Mercury in wellhead gas was initially a concern, however, a paper is provided as Appendix 1 discussing why mercury should not be an issue.

Liquid Petroleum Gas (LPG): LPG is propane and/or butane often with small amounts of propylene and butylene sold as a pressurized liquid. LPG is included in this definition of Natural Gas.

Gaseous Fuels Derived from processing of crude oil, petroleum or petrochemicals: The Petroleum Environmental Research Forum Project 92-19 (PERF Data) found no significant difference in air toxic emissions between burning natural gas, as defined above, and these process derived gaseous fuels. Enclosed in Appendix 2, there is a paper entitled "MACT Floor Documentation -- Rationale for Broad Definition of Gaseous Fuels" which supports the argument of incorporating gaseous fuels derived from processing of crude oil, petroleum or petrochemicals into the definition of Natural Gas.

However, at this time, because of not being able to review and digest the information, the ICCR Coordinating Committee did not come to consensus on this definition and is deferring to the EPA the decision of the incorporation of these process derived fuel types with Natural Gas.

B. Oils

Distillate Oil (also called unheated oil): Fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Material in ASTM D396-78, Standard Specifications for Fuel Oil. (40 CFR 60.41b)

Residual Oil (also called heated oil): Crude oil, and all fuel oil numbers 4,5, and 6 as defined by the American Society of Testing and Materials in ASTM D-396-78, Standard Specifications for Fuel Oils. (40 CFR 60.41b)

C. Coal

The coal definition is the same as that from 40 CFR 60.41b (NSPS Subpart Db) – Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank, coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures are also included in this definition.

III. INITIAL SELECTION PROCESS

A. Initial Review of Data and Reference Material

For each type of fuel category for Fossil Fired Boilers (natural gas, distillate oil, residual oil, and coal) several reference sources were reviewed to determine an initial list of HAPs of Interest. These initial HAP references included: data from API, data from WSPA, Dioxin presentation for the ICCR, AP-42, EPA Emissions Database, EPA Utility Boiler HAPs Study, Great Waters Program documents, EPA's proposed list of 40 priority HAPs for further analyses under the Urban Air Toxic Program, EPA's draft list of Priority HAPs, and others.

The EPA Utility Boiler HAPs Study can be used as an example of how a list of HAPs of Interest was developed by a particular resource. The EPA reviewed all of the emissions from large fossil fuel fired utility boilers. By modeling the actual emissions, the EPA looked at the health risks. They plugged the emission model information into health effects models to determine the inhalation and cancer risks. From this analysis, the EPA determined which HAPs should be further studied as HAPs of Interest in their Utility HAPs study.

When a HAP was found on multiple resource lists it was further investigated as a HAP of Initial Concern. HAPs not appearing on the various reference lists were not further investigated.

B. Compilation of Emission Data

To further investigate HAPs of Initial Concern, various emission databases were reviewed. The emission database references include: EPA Utility Boiler HAPs Study, API/WSPA study, the Fifth Edition of AP-42, EPA Emissions Database, to mention a few.

Comparisons were then run using the worst emissions or median values from multiple tests (coal) from the various data reference sources. These "worst case" actual emissions were used to determine the total emissions US-wide and to calculate emissions for a 10 MM BTU/hr boiler, a 100 MM BTU/hr boiler and a 250 MM BTU/hr boiler. These boiler sizes were picked because they represent the sizes of typical industrial boilers. These calculated boiler emissions were then used as a standard for comparison against the screening models, as described below.

IV. COMPARISON OF EMISSION DATA TO DEMINIMIS AIR MODEL – INITIAL SCREENING

There was an initial screening performed by comparing the boiler emissions from a 250 MM BTU/hr boiler with a New Hampshire Department of Environmental Services (NHDES) De minimis Emission Model. From the Model a list of draft de minimis limits were determined by the NHDES. It was believed then, that any emissions that were lower than the NHDES proposed deminimis limits could automatically be dropped from the list of concerns.

This NHDES Screening Model used the following conservative assumptions in a US EPA air pollution dispersion model for a "typical facility with downwash problems":

- Emission rate = 1 lb/hr;
- Stack Height = 10 ft;
- Stack diameter = 1 ft;
- Volume flow = 100 ACFM;
- Temperature = 68 degrees F; and
- Building height = 10 ft, width = 20 ft and length = 20 ft.

This equates to a stack velocity of about 1 to 2 ft/sec. However, in industry, economic stack velocities usually start at about 10 ft/sec. and can go as high as 100 ft/sec. Typical stack gas velocities are usually more than 20 ft/sec. The temperature in the model stack is only 68 degrees F. Most industrial boiler stack temperatures are at least 200 to 300 degrees F, even with efficient economizers. A temperature of 68 degrees will cause zero buoyancy of the exiting gas. This type of model would probably not allow drafting in a boiler.

Basically this model guarantees maximum downstream downwash of any constituents and will predict much higher concentrations of emitted species at the point of impact than would be found under more realistic conditions. Finally, the model de minimis limits were set based on the health effects concentrations that the downstream receptors would encounter. Then the conservative emission rates were backcalculated. All of this is discussed to show the conservativeness of the model and the belief that if the actual emissions for a 250 MM BTU/hr boiler were less than the deminimis emissions then the HAP would be at low risk for posing any health problem.

Therefore, any HAP whose emissions were below the de minimis levels from the de minimis model were initially considered for dropping from the list HAPs of Initial Concern.

V. SECONDARY COMPARISON CONSIDERATIONS

As stated above the NHDES model is an extremely conservative air emission model. This initial model was revised to use more realistic boiler stack parameters and US EPA refined air pollution dispersion models. The boiler stack parameters were derived from an analysis of existing boilers burning oil and wood permitted in New Hampshire. The new stack parameters are shown in Appendix 3. It should be noted that the model used for the comparison was a dispersion model set up for wood firing conditions. At the time of this screening gas and coal model data were not available. However, in most cases actual boiler groundlevel concentrations used for the comparison were several orders of magnitude below the NHDES second screen wood model emissions.

This comparison was then made with the remaining constituents on the HAPs of Initial Concern list. Those constituents whose emission rates from a 250 MM BTU/hr boiler were below this second round screening were then dropped or discussed for dropping.

Then the final list of HAPs of Interest was determined. There were several constituents that may have been dropped from one or both screenings, but were left on the List of Concern for one of the following reasons:

- Multiple boilers in an area may emit quantities of the HAP that may cause risk to the population;

- The HAP may appear on the proposed Urban Air Toxic list (112(k)) and is at an emission level that may cause some concern (examples – formaldehyde, dioxans/furans);

- The HAP may appear on a list of extreme toxicity (no definition of the limits) and is at an emission rate that may cause some concern. Additionally the HAP is purported to be a combustion by-product (examples- methylene chloride and 1,1,2,2-tetrachloroethane); and

- The HAP had little or no emission data.

A set of tables showing each fossil fuel type is shown in Appendix 4. These tables show the rationale for leaving the HAP on the list of HAPs of Concern. It is a summary of the concepts shown above.

VI. HAPS OF INTEREST LIST

Below is a list of the HAPs of Interest for each of the fossil fuel groups (gas, distillate oil, residual oil and coal).

Table 1. Gas HAPs of Interest List

Chemical	Chemical
Benzene	Phosphorus
Toluene	Dioxin
Hexane	Cadmium Compounds
POM's	Chromium Compounds
Formaldehyde	Cobalt Compounds
Nickel	Lead Compounds
Acetaldehyde	Manganese compounds
Dibenzofurans	

Table 2. Distillate Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Acetaldehyde	Nickel

Table 3. Residual Oil HAPs of Interest List

Chemical	Chemical
Benzene	Arsenic
1,3 Butadiene	Beryllium
Dioxins/Furans	Cadmium
POM's/Naphthalene	Chromium
Hydrochloric Acid	Lead
Hydrogen Fluoride	Manganese
Formaldehyde	Mercury
Selenium	Nickel
	Phosphorus

Table 4. Coal HAPs of Interest List

Chemical	Chemical
Benzene	
Isophorone	Nickel
Dioxins	Phenol
POMs	Selenium
Hydrochloric Acid	Cyanide
Hydrogen Fluoride	Acrylamide
Acetaldehyde	Acrylonitrile
Acrolein	2-chloro-acetophone
Arsenic	Ethylene Dibromide
Beryllium	Formaldehyde
Cadmium	Hexachlorobenzene
Chromium	Methyl Chloride
Cobalt	Methyl Iodide
Lead	N-Nitrosodimethylamine
Phosphorus	1,1,2,2 Tetrachloroethane
Manganese	Antimony Compounds
Mercury	Radionuclides

APPENDIX 1

MERCURY IN WELLHEAD GAS

MERCURY IN WELLHEAD GAS

<u>Finding – Mercury emissions from wellhead gas combustion are insignificant nationwide, and even in those remote geographical areas with the highest mercury concentrations, emissions are about two pounds a year or less.</u>

Wellhead Gas

"Wellhead"[5] gas is natural gas produced directly from underground reservoirs without having removed the natural gas liquids (butane, propane, gasoline, etc.). The Btu content of this gas can range as high as 1200 Btu as compared to approximately 1000 Btu for natural gas being transported to market via Department of Transportation (DOT) regulated pipelines.

"Natural gas", is pipeline quality gas located downstream of the natural gas plant. Wellhead gas is processed and the natural gas liquids are removed to produce marketable natural gas. Testing by the Gas Research Institute (GRI) of natural gas demonstrates it has only a trace mercury concentration as noted in GRI's Report[3]. The maximum mercury concentration found in natural gas was 0.2 micrograms per cubic meter (ug/m^3).

Wellhead gas is only used as fuel in oil and gas industry operations where processed gas cannot be obtained from a natural gas plant. This lack of processed gas could be due to the absence of a DOT regulated pipeline to market or the remaining gas in the producing field is depleted to such an extent that the gas plant has been shut down due to economic considerations. Wellhead gas can be used in boilers, heater treaters, or IC engines at isolated oil and gas field locations.

Boilers are rarely used at oil and gas facilities outside of California. Boilers are used in California for generating steam for injection into high viscous oil reservoirs for recovery purposes. Nearly all of the boilers in California use natural gas with a few using wellhead gas. Mercury is not found in California wellhead gas above trace quantities (1-100 ug/m^3).

Heater treaters and IC engines use wellhead gas at certain oil and gas facilities nationwide. The only know geographical area with mercury greater than 100 ug/m^3 is in South Texas (2-3 County Area)[4].

Mercury in Wellhead Gas

Elemental mercury[1] was found in wellhead gas as early as 1969 in Holland. In addition, mercury corrosion was detected in an aluminum spiral wound heat exchanger at a liquid natural gas plant in Skikda, Algeria in 1974. Since this time, mercury in wellhead gas has become a major concern in cryogenic gas processing industries. These industries often use aluminum heat exchangers in their processes. Mercury corrosion of aluminum exchangers has led to several equipment failures since the problems at Skikda.

Mercury forms[1] are present in some wellhead gas and wellhead gas associated condensates, as organometallic and inorganic compounds, and in the elemental (metallic) form depending on the origin of the gas. The elemental form can be found in either the vapor or liquid phase. The organometallic and inorganic compounds drop into the liquid phase in any fractionation of the natural gas streams. Vapor phase elemental mercury is a primary culprit in corrosion of aluminum exchangers inside cryogenic cold boxes. Operators typically remove mercury upstream of the natural gas plant to prevent corrosion of aluminum equipment within the plant as well as prevent corrosion at facilities downstream of the plant. Mercury is not removed from wellhead gas combusted at production sites.

Mercury has been found in wellhead gas at a few geographic locations nationwide. Mercury concentrations range from 0.02 – .40 micrograms per cubic meter in the Gulf Coast Area[2]; 5 – 15 micrograms per cubic meter in the Overthrust Belt/Kansas[2,4]; and as high as 500 micrograms per cubic meter in some South Texas fields[4]. Gas plant operators test for mercury because cryogenic fractionation processes can be damaged by mercury concentrations as low as 1-10 micrograms per cubic meter. Operators utilize different processes worldwide to remove mercury from the plant inlet gas stream to protect sensitive components from corrosion. Again, the mercury removal systems are intended to protect the process equipment in the gas processing plant; they have nothing to do with improving combustion. In fact, most cryogenic plant operators do not find it necessary to remove trace mercury concentrations from wellhead gas to prevent corrosion.

<u>Wellhead Gas as Fuel</u>

There are three main reasons why mercury in wellhead gas is not significant.:

1. Wellhead gas is nearly always used in oil and gas operations upstream of the natural gas plant. The typical type of equipment used in these operations is small and widely separated geographically. Nearly all heaters are smaller than 3 MMBTU/hr and most internal combustion engines are less than 1000 horsepower in size. Most of these production facilities will not have more than one of these emission sources per site.

2. Concentrations of mercury in produced wellhead gas are very low in the United States. Mercury concentrations range from 0.02 micrograms per cubic meter to 500 micrograms per cubic meter. Consequently, annual emissions of mercury from typical oil and gas production equipment are very low as calculated[6] in the following tables:

Gulf of Mexico (0.4 ug/m^3 mercury in wellhead gas)

Equipment Size	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.00066	3.31×10^{-7}
1000 HP IC Engine	0.00187	9.36×10^{-7}

Overthrust Belt/Kansas (15 ug/m^3 mercury in wellhead gas)

Equipment Size	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.025	1.26×10^{-5}
1000 HP IC Engine	0.070	3.51×10^{-5}

South Texas (500 ug/m^3 mercury in wellhead gas)

Equipment BTU Heater	Pounds/Yr.	Tons/Yr.
3 Million BTU Heater	0.820	4.10×10^{-4}
1000 HP IC Engine	2.320	1.16×10^{-3}

Note: These emission calculations assume that the total mercury in the fuel gas is emitted to the atmosphere after combustion; leading to a potential overestimate. In addition, the mercury estimates may be high because they are based on pure methane combustion which has a lower Btu value resulting in a higher fuel throughput.

3. Wellhead gas containing more than trace concentrations of mercury is only found in South Texas. In this geographical area, oil and gas production facilities are generally located in arid and rural areas.

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APPENDIX 2

MACT Floor Documentation
Rationale for Broad Definition of Gaseous Fuels

MACT Floor Documentation
Rationale for Broad Definition of Gaseous Fuels

BACKGROUND

Emissions data on HAPs and criteria pollutants originated from three primary sources.

First, source test results collected under the California Air Toxics "Hot Spots" Inventory and Assessment Act (AB2588) have been compiled and quality reviewed in a joint effort by the Western States Petroleum Association (WSPA), the California Air Resources Board (CARB), and the American Petroleum Institute (API). The results of this investigation are compiled in the 3-volume Draft Report titled "Development of Toxics Emission Factors for Petroleum Industrial Combustion Sources" (D. W. Hansell and G. C. England, EER Corporation, September 1997). It was provided to the US EPA in October 1997. The validation and verification processes used to quality assure these data makes this the most reliable and comprehensive compilation of field emission source test data for petroleum industry combustion sources. The final report was provided to EPA in September 1998.

The second source of emissions test data came from the Petroleum Environmental Research Forum (PERF) 92-19 "Toxic Combustion Byproducts" project. In 1992 PERF initiated a Cooperative Research and Development Agreement (CRADA) with the U.S. Department of Energy, and with EPA participation, performed an experimental and fundamental investigation of chemical and physical mechanisms governing organic HAP formation, destruction, and emissions. These tests on full-scale burners were performed at the Sandia National Laboratories/Livermore. This program produced data of very high quality that shed light on many of the key questions surrounding the field data. The results of this project are summarized in a paper titled "Organic Hazardous Air Pollutant Emissions from Gas-Fired Boilers and Process Heaters" (G.C. England and D.W.Hansell, EER Corporation, July 1997). The PERF 92-19 CRADA Final Report, "The Origin and Fate of Toxic Combustion Byproducts in Refinery Heaters: Research to Enable Efficient Compliance with the Clean Air Act" (August 5, 1997), can be accessed at http://www.epa.gov/ttn/iccr/dirss/perfrept.pdf.

Lastly, the ICCR Emissions Database, V.2, provides a compilation of emissions test data made available from existing electronic databases such as STIRS, and other information from state and local agencies. Emissions information collected from the 114 ICR survey was also added to this database.

CONCLUSIONS

Based on the discussion above and the references cited therein.

- ***HAP emissions from all gas-fired sources are generally very low, but exhibit inherent variability associated with process fluctuations and sampling and analysis uncertainties.***

The PERF data referenced above demonstrate that HAP emissions from typical industry gas fired burners, under a variety of operating conditions are all very low, at or near the detection limits of the best measurement methods. In addition, field source test data, such as the WSPA/API database indicate that annual total HAP emissions from operating gas-fired heaters and boilers are well below the major source definition.

- ***HAP emissions from devices fired by either natural gas or petroleum processing derived gas are similar, on a Btu basis.***

The controlled laboratory testing (PERF study) and the WSPA/API field test data demonstrate that emissions factors derived independently for different gaseous fuels are indistinguishable, when measurement uncertainty and process variability are taken into account (Figures 1). The emission factor derivation process accounts for the different heat content of the variety of the gases used in practice, and which like natural gas, consist primarily of hydrocarbons mixtures.

- ***HAP emissions from gas-fired boilers and process heaters are equivalent.***

Design practices are such that the same burner types are used for constructing both gas-fired process heaters and boilers. In addition, the field emissions data for boilers and process heaters, fired by a variety of gaseous and liquid fuels, was shown to be similar (Figure 2). The data demonstrate that emissions from boilers or process heaters vary by size (heat input) but are otherwise expected to be equivalent.

RECOMMENDATIONS

For the purposes of subcategorizing boilers – the ICCR Coordinating Committee recommends that a single subcategory be established for devices firing the following gaseous fuels:

1. *Natural Gas/Wellhead Gas:* a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane;

2. *Liquid Petroleum Gas:* as defined by the American Society of Testing and Materials in ASTM D1835-82, Standard Specification for Liquid Petroleum gases.

3. *Petroleum Derived Gas:* Gaseous fuel derived from the processing of crude oil, petroleum, or petrochemicals.

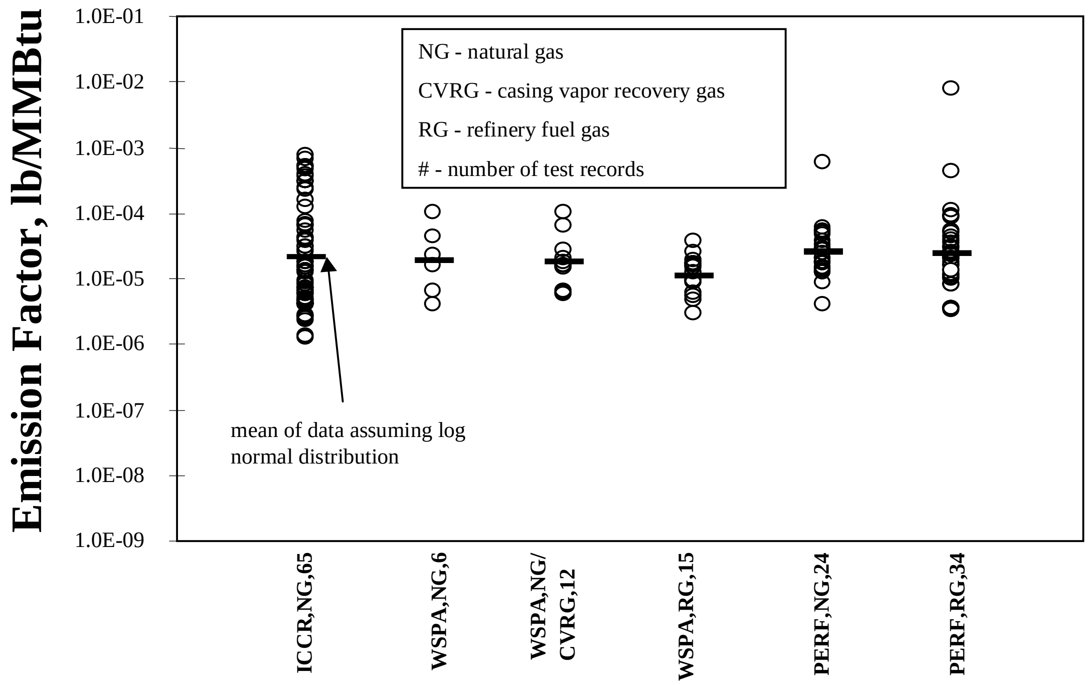
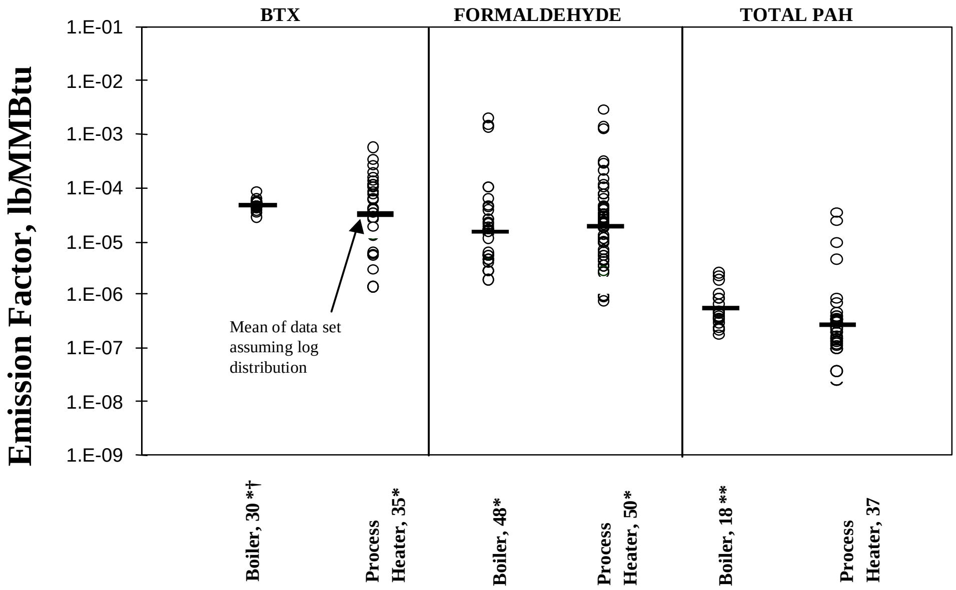


Figure 1. Formaldehyde emissions as a function of fuel type for gas fuel fired boilers (ICCR, WSPA, and PERF data).



* Includes crude, FO #6, and gaseous fuel (primarily gas)

** Includes FO #6 and gaseous fuel (primarily gas)

† Number following label = number of test records

Figure 2. Comparison of HAP emissions data for Boilers and Process Heaters (WSPA data).

APPENDIX 3

Modeling for Hypothetical Oil and Wood Boilers

ICCR Modeling for Hypothetical Oil and Wood Boilers

Runs were made for flat, complex and simple terrain, assuming relatively hilly terrain in the latter two cases. Both annual and 24-hour average concentrations were calculated. The following inputs were used:

Parameter	Oil Condition	Wood Condition
Stack Height	200 ft	180 ft
Stack Diameter	9 ft	7.5 ft
Volume Flow	150,000 ACFM	125,000 ACFM
Gas Temperature	350° F	330° F
Emission Rate	1 lb/hr	1 lb/hr
Building Height	90 ft	90 ft
Building Width	80 ft	80 ft
Building Length	80 ft	80 ft

The above inputs were derived from a study of large boilers burning both oil and wood which have been permitted in the state of New Hampshire. The building data are representative of a typical boiler building for facilities which have previously been modeled. Using this size building, small but measurable downwash effects were predicted.

For the simple terrain modeling, gradually rising terrain was assumed in all directions, typical of a valley situation with surrounding rising hills. Elevations were assumed to reach stack top just beyond one kilometer and plume height close to three kilometers. This is conservative, though not unrealistic, topography and, in conjunction with the flat terrain modeling, presents a full range of terrain conditions.

Using the above input data, the following maximum impacts were predicted:

Maximum 24-Hour Average Concentrations

	Oil Condition			Wood Condition		
Terrain	**Flat**	**Simple**	**Complex**	**Flat**	**Simple**	**Complex**
Screening Impact (ug/m^3)	0.13	**0.47**	0.23	0.21	**0.68**	0.31
Distance (m)	990	1200 (a)	3000 (b)	270	1100 (a)	2500 (b)
Refined Impact (ug/m^3)	0.12	**0.30**	(c)	0.18	**0.42**	(c)
Distance (m)	300	300		300	1000	

Maximum Annual Average Concentrations

	Oil Condition			Wood Condition		
Terrain	**Flat**	**Simple**	**Complex**	**Flat**	**Simple**	**Complex**
Screening Impact (ug/m^3)	0.033	**0.118**	0.058	0.053	**0.170**	0.078
Distance (m)	990	1200 (a)	3000 (b)	270	1100 (a)	2500 (b)
Refined Impact (ug/m^3)	0.008	**0.029**	(c)	0.017	**0.047**	(c)
Distance (m)	300	2000		300	1000	

Notes: (a) stack top height was assumed to be reached at this distance
(b) plume height was assumed to be reached at this distance
(c) modeled in conjunction with simple terrain (maximum impacts)

APPENDIX 4

Rationale for Selection of Fossil Fuel HAPs

Table A – Gas HAPs of Interest

Table B – Distillate Oil HAPs of Interest

Table C – Residual Oil HAPs of Interest

Table D – Coal HAPs of Interest

TABLE A. SELECTION RATIONALE - GAS HAPS OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volitiles	Benzene	X		X		X			
	Toluene								O3 Precursor
	Hexane	X	Not Modeled					X	
Semi Volatiles	POMs			X	X	X	X		
Carbonyls	Acetaldehyde			X					
	Formaldehyde	X		X		X			
Metals	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Cobalt	X			X				
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Nickel	X		X	X	X	X		
Other	Dibenzofurans	ND	N/A	X	X	X	X	X	X
	Dioxins	ND	N/A	X	X	X	X	X	X
	Phosphorus	X	Not Modeled						

TABLE A. SELECTION RATIONALE - GAS HAPS OF INTEREST (Continued)

(1)	Comparison with conservative NHDES Model (250 MM BTU/hr boiler Comparison).
(2)	Comparison with industrial NHDES Model (250 MM BTU/hr boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3)	Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4)	Listed on one or more of the following Great Lakes Area Programs:
	Great Waters Progam, CAA Subsect. 112(m)
	Great Lakes Binational Toxics Strategy, International Joint Commission, *Focu*, Vol. 22, Issue 2, 1997
	Critial Pollutant from EPA Revised Draft of Lake Michigan Lakewide Management Plan For Tox. Pollutants, 8/30/93
	Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5)	Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6)	Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
N/D -	Not enough Data
N/A -	Not Applicable

TABLE B. SELECTION RATIONALE - DISTILLATE OIL HAPs OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volatiles	Benzene	X(1a)	(1a)	X		X			
	1,3 Butadiene	1(a)	Not Modeled	X					
Semi Volatiles	Dioxins/Furans	ND	N/A	X	X	X	X	X	
	POMs/naphthalene	ND	N/A	X	X	X	X		
Acid Gases	Hydrochloric acid	ND						X	
	Hydrogen fluoride	ND	N/A					X	
Aldehydes/ketones	Formaldehyde			X		X			
	Acetaldehyde	1(A)		X				X	
Metals	Arsenic	X		X		X	X		
	Beryllium	X		X		X	X		
	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Mercury	X		X	X	X	X		
	Nickel	X		X	X	X	X		

(1) Comparison with conservative NHDES Model (250 MM BTU/hr boiler Comparison)
(1a) Compound Values assumed the same as for Gas. According to PERF Analysis and Report.

TABLE B. SELECTION RATIONALE - DISTILLATE OIL HAPs OF INTEREST (Continued)

(2) Comparison with industrial NHDES Model (250 MM BTU/hr boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
Great Waters Progam, CAA Subsect. 112(m)
Great Lakes Binational Toxics Strategy, International Joint Commission, *Focus*, Vol. 22, Issue 2, 1997
Critial Pollutant from EPA Revised Draft of Lake Michigan Lakewide Management Plan For Tox. Pollutants, 8/30/93
Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough Data
N/A - Not applicable

TABLE C. SELECTION RATIONALE - RESIDUAL OIL HAPs OF INTEREST

Classification	Component	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
Volatiles	Benzene	X		X		X			
	1,3 Butadiene	ND	N/A	X				X	
Semi Volatiles	POMs/naphthalene	ND	N/A	X	X	X	X	X	
Acid Gases	Hydrochloric acid	X							
	Hydrogen fluoride	X							
Aldehydes/ketones	Formaldehyde	X		X		X			
Metals	Arsenic	X		X		X	X		
	Beryllium	X		X		X	X		
	Cadmium	X		X		X	X		
	Chromium	X		X		X	X		
	Lead	X		X	X	X	X		
	Manganese	X		X	X	X	X		
	Mercury	X		X	X	X	X		
	Nickel	X		X	X	X	X		
	Selenium	X				X			
	Phosphorus	X							
Other	Dioxins/Furans	ND	N/A	X	X	X	X	X	

TABLE C. SELECTION RATIONALE - RESIDUAL OIL HAPs OF INTEREST (Continued)

(1) Comparison with conservative NHDES Model (250 MM BTU/hr boiler Comparison)
(2) Comparison with industrial NHDES Model (250 MM BTU/hr boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
Great Waters Progam, CAA Subsect. 112(m)
Great Lakes Binational Toxics Strategy, International Joint Commission, *Focu*, Vol. 22, Issue 2, 1997
Critial Pollutant from EPA Revised Draft of Lake Michigan Lakewide Management Plan For Tox. Pollutants, 8/30/93
Great Lakes Commissions, Great Lakes Regional Air Toxics Emissions Inventory of 49 Targeted Compounds
(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough Data
N/A - Not Applicable

TABLE D. SELECTION RATIONALE - COAL HAPS OF INTEREST

CAS Number	Chemical Name	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
75070	Acetaldehyde			X					
107028	Acrolein			X			X		
79061	Acrylamide	X	Not Modeled	X		X	X		
107131	Acrylonitrile	X		X		X	X		
71432	Benzene	X		X		X			
2142689	2-chloro acetophenone	X	Not Modeled						
106934	Ethylene dibromide (Dibromoethane)			X		X	X		
50000	Formaldehyde	X		X		X			
118741	Hexachlorobenzene	X	Not Modeled		X		X		
7647010	Hydrochloric acid	X	Not Modeled						
7664393	Hydrogen fluoride (Hydrofluoric acid)	X	Not Modeled						
78591	Isophorone								
74873	Methyl chloride (Chloromethane)			X		X			
74884	Methyl Iodide	ND	N/A					X	
62759	N-Nitrosodimethylamine	X	Not Modeled						
108952	Phenol				X				
7723140	Phosphorus	X	Not Modeled						
79345	1,1,2,2-Tetrachloroethane			X					
0	Antimony Compounds	X							
0	Arsenic Compounds	X		X		X	X		
0	Beryllium Compounds	X		X		X	X		

TABLE D. SELECTION RATIONALE - COAL HAPS OF INTEREST (Continued)

CAS Number	Chemical Name	NHDES De minimis (1)	NHDES Indust. Model (2)	Urban Air Toxics List (3)	Great Lakes Stretegy/ Great Waters (4)	Health Risk in Detroit (5)	Highly Toxic HAP (6)	Not Enough Data	Other
0	Cadmium Compounds	X		X		X	X		
0	Chromium Compounds	X		X		X	X		
0	Cobalt Compounds	X			X				
0	Cyanide Compounds1	X	Not Modeled						
0	Lead Compounds	X		X	X	X	X		
0	Manganese Compounds	X		X	X	X	X		
0	Mercury Compounds	X		X	X	X	X		
0	Nickel Compounds	X		X	X	X	X		
0	Polycylic Organic Matter (POM)	ND	N/A	X	X	X	X	X	
0	Radionuclides	X	Not Modeled						On EPA Utility Coal HAPs for further Study
0	Selenium Compounds	X				X			
	Dioxins	ND	N/A	X	X	X	X	X	

(1) Comparison with conservative NHDES Model (250 MM BTU/hr boiler Comparison)
(2) Comparison with industrial NHDES Model (250 MM BTU/hr boiler Comparison). Only model data comparison available was for wood boiler emissions.
(3) Hazardous Air Pollutant Area Source Program (CAA Subsect. 112(k) - Urban Air Toxics Study Priority HAP List of 40
(4) Listed on one or more of the following Great Lakes Area Programs:
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Great Lakes Binational Toxics Strategy, International Joint Commission, *Focu*, Vol. 22, Issue 2, 1997
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(5) Health Risk in Detroit - Ref. The Transboundary Air Toxics Study, EPA Final Summary Report, Dec. 1990
(6) Highly Toxic HAP's (Potency), Ref. EPA's Draft of Priority HAP's (5/13/97)
ND - Not enough data in emission database.
N/A - Not Applicable

ATTACHMENT V

Cost of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Industrial Combustion Coordinated Rulemaking (ICCR)
Federal Advisory Committee

September 16, 1998

Table of Contents

I. INTRODUCTION

This paper presents the assessment of the ICCR Coordinating Committee with regard to the potential cost-effectiveness of oxidation catalysts used to control hazardous air pollutant (HAP) emissions from combustion turbines. This assessment is made in the context of providing recommendations that contribute to EPA's evaluation of "above-the-floor" MACT options for existing combustion turbines. In accordance with Section 112(d) of the Clean Air Act, EPA must consider costs in evaluating above-the-floor options for MACT, along with any non-air quality health and environmental impacts and energy requirements.

In previous materials, the ICCR Coordinating Committee recommended to EPA, based on available information, that it is not possible to identify a best performing subset of existing combustion turbines, and as a result, there is no MACT floor for the existing population of combustion turbines in the United States. Therefore, to determine MACT, EPA must evaluate emission reduction technologies above the floor for existing combustion turbines. The ICCR Coordinating Committee has reviewed emission reduction technologies for existing turbines to identify controls that may be considered in the above-the-floor MACT analysis. Based on this review, oxidation catalysts for the reduction of carbon monoxide (CO) may reduce emissions of organic HAPs from combustion turbines. The CO oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct and serves to oxidize CO and hydrocarbons to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the fuel gas stream (EPA, 1993a). Therefore, EPA must evaluate oxidation catalysts as an "above-the floor" MACT option for existing combustion turbines. This paper addresses the costs and the HAP air emissions reductions that may be achieved with oxidation catalysts. EPA may consider other factors, such as non-air quality environmental impacts, energy requirements, and secondary pollutants, in assessing above-the-floor MACT.

The approach taken in this paper is to present a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for model combustion turbine units, which range in size from 1.13 megawatts (MW) to 170 MW. To determine cost-effectiveness for the base case analysis, quantitative estimates for the three inputs required to estimate cost-effectiveness were developed:

1. The baseline HAP emissions of combustion turbines before emissions control;

2. The costs of acquiring and operating oxidation catalysts; and

3. The performance of oxidation catalysts in reducing HAP emissions.

For each of these inputs this paper presents the key factors considered important. In assessing these three areas a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for each model turbine is presented. The quantitative cost-effectiveness for each model was calculated by dividing the total annual cost by the mass of annual HAP emission reductions. Cost-effectiveness is expressed as dollars per megagram of HAP emission reduction. A megagram (Mg) is one metric ton, or approximately 1.1 U.S. tons. The paper also presents a qualitative discussion on complicating factors that could cause the estimated cost-effectiveness base case to be different in real-world situations.

Section II provides a summary of the base case assumptions. Sections III, IV, and V present the quantitative estimates and complicating factors for each of the three inputs for cost-effectiveness: baseline HAP emissions, control costs, and emission reduction. The range of cost-effectiveness values and the base case cost-effectiveness for each model turbine are presented in Section VI. Conclusions and recommendations are presented in Section VII.

II. SUMMARY OF BASE CASE ASSUMPTIONS

For the base case cost-effectiveness analysis, seven model turbines that range in size from 1.13 megawatts (MW) to 170 MW were selected:

- Model 1 -- GE PG 7121EA, 85.4 MW;
- Model 2 -- GE PG 7231FA, 170 MW;
- Model 7 -- GE PG 6561B, 39.6 MW;
- Model 9 -- GE LM2500, 27 MW;
- Model 13 -- Solar Centaur 40, 3.5 MW;
- Model 15 -- Solar Mars T12000, 9 MW; and
- Model 17 -- Solar Saturn T1500, 1.13 MW.

These seven model turbines were selected to provide the basis to estimate the national impacts associated with any future combustion turbine MACT standard. A complete list of model turbines is provided as Appendix A.

As originally developed, the list of model turbines incorporates the fuels used, the typical hours of operation for a unit, the industry sector that may use a turbine, the presence of a duct burner, and information about space limitations. The base case assumes that each turbine is operated for 8,000 hours annually and operates at 80% rated load or greater.

The base case analysis is also limited to natural gas-fired model turbines. Natural gas is the predominant fuel used by combustion turbines in the ICCR database. Some 54.3% of the turbines in ICCR Inventory Database Version 3 were reported as firing natural gas exclusively. Another 14.5% were reported as being dual fuel units, and it is expected that these units primarily use natural gas. In addition, the quantitative analysis focuses on natural gas-fired turbines because fuels other than natural gas introduce complicating factors. For example, a catalyst vendor indicated that for turbines that operate continuously on fuel oil, it is preferable to use a special catalyst formulation that is unaffected by sulfur exposure (Chen et al., 1993).

In addition, the base case quantitative analysis is limited to uncomplicated retrofit installations. Although a number of situations could complicate a retrofit installation of an oxidation catalyst, especially complications due to space limitations, time did not permit quantitative estimates for these complications. Therefore, the base case includes only a qualitative description of retrofit complications, and no costs for retrofit complications are included in the cost-effectiveness values. Most retrofit installations for existing turbines would involve some complicating factors and, therefore, the costs to retrofit the units with oxidation catalysts would be higher in general, and in some cases much higher, than the costs presented in this base case analysis.

III. BASELINE HAP EMISSIONS FROM COMBUSTION TURBINES

Emissions data included in the ICCR Emissions Database to identify HAPs emitted by natural gas-fired combustion turbines were used to estimate baseline emission rates. Mass emissions for each HAP were calculated using emission factors (lb/MMBtu). Since the rate of emissions reported for natural gas-fired combustion turbines varies, two emission factors were used to estimate baseline emissions -- the highest emission factor and the average emission factor.

Further discussion of the baseline emissions data used in this analysis and complicating factors is provided below.

A. Source of Baseline HAP Emissions Data

The information available about the emissions of HAPs from combustion turbines is included in the ICCR Emissions Database. The ICCR Coordinating Committee believes that the emissions database adequately represents the turbine population, and that these source test data are a sufficient basis for emission factors for a cost-effectiveness analysis.

The current version of the emissions database includes over 70 source tests collected by EPA, many of which involve replicate sampling and analysis runs. For each test report EPA has calculated consistent emission factors for measured HAPs based on the emissions concentration reported. A description of the development of the emissions database, including assumptions used in the calculations, is provided as Appendix B. Also, EPA performed a quality assurance review of each test report and determined which reports should be considered adequate for general assessment of HAP emissions from combustion turbines. These review criteria are included in Appendix C. When possible, pertinent information identified as missing from test reports was obtained by contacting the tested facilities. Only those source test data considered appropriate for use in evaluating HAP emissions were used to calculate emission factors.

B. Criteria to Include Emission Test Data in Baseline Emissions

A subset of combustion turbine emission tests from the ICCR Emissions Database was identified to develop the baseline emission factors for this cost-effectiveness analysis, based on the following criteria:

1. Because the baseline emissions estimate is to be done only for natural gas, emission factors were included only from tests of combustion turbines firing natural gas [42 of the 70 test reports in the database are for natural gas.];

2. Only test reports that were judged to be complete and to have met quality assurance criteria were included [Of the 42 tests for natural gas, 8 reports were not complete or did not meet QA\QC criteria.]; and

3. Because combustion turbines typically operate near full load, emission factors were extracted only for combustion turbine tests that were conducted at above 80% of rated load [Of the 42 tests for natural gas, 11 reports were conducted at less than 80% rated load.].

A list of the tests excluded based on the above criteria is provided in Appendix D.

C. Emission Factors for Baseline HAP Emissions

For those test reports in the ICCR Emissions Database that met the criteria discussed above, emission factors were included in this cost-effectiveness analysis for those HAPs measured at concentrations above the test method's detection limit in at least one run. Therefore, none of the emission factors are based solely on non-detects.

For natural gas-fired turbines, nine HAPs were measured above the detection limits in at least one run. Both the highest emission factor and the average emission factor were used for the base case analysis. The emission factors are presented in Table 1. Baseline annual emissions for each model turbine were calculated using these emission factors. The heat input was calculated

Table 1. HAPs Emission Factors for the Base Case Analysis

Pollutant	Highest Emission Factor		Average Emission Factor	
	Test	(lb/MMBtu)	(lb/MMBtu)	No. of Tests
Formaldehyde	Test 316.1.1	5.61E-03	7.13E-04	22 Tests
Toluene	Test 28	7.60E-04	1.42E-04	7 Tests
Acetaldehyde	Test 11	3.50E-04	9.12E-05	7 Tests
Xylenes	Test 18	1.20E-04	4.59E-05	5 Tests
Ethylbenzene	Test 18	4.10E-05	4.10E-05	1 Test
Benzene	Test 315.1	3.91E-05	1.03E-05	11 Tests
PAHs	Test 7	7.32E-06	2.23E-06	4 Tests
Acrolein	Test 18	6.08E-06	5.49E-06	2 Tests
Naphthalene	Test 7	3.31E-06	1.46E-06	3 Tests

Source: ICCR Emissions Database for Combustion Turbines

by converting the model turbine rating (MW) to MMBtu/hr and dividing by the turbine efficiency, assumed to be 35%. The baseline annual emissions were then calculated using the heat input (MMBtu/hr), the emission factor (lb/MMBtu), and the annual operating hours (hr/yr). The baseline emissions (megagrams/year) for each model turbine are presented in Table 2. [Note: The emission estimates used in this analysis are presented as emissions at the stack outlet. The emissions estimates do not address ambient air dispersion of the pollutants, nor ground-level concentrations.]

D. Complicating Factors

The emission factors used for the base case cost-effectiveness analysis, as presented in Table 1, represent a necessary simplification of actual HAP emissions which could be expected in the existing population of combustion turbines in the United States. The following complicating factors would change the baseline emissions of certain combustion turbines in some cases:

1. The use of the highest HAP emission factors reported tends to overestimate HAP baseline emissions;

2. For the "highest" case, the highest HAP emissions factors for each pollutant were used. It has not been shown that all these "highs" would occur simultaneously from a combustion turbine. In fact, it is not likely that all the "highs" for all pollutants would occur simultaneously. Therefore, total HAP emissions are

Table 2. Baseline Emissions (Mg/yr) for Each Model Turbine

Baseline Emissions (Mg/yr)-- Highest Emission Factor

Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	33.810	4.580	2.109	0.723	0.247	0.236	0.044	0.037	0.020	41.806
1	85.4 MW	16.984	2.301	1.060	0.363	0.124	0.118	0.022	0.018	0.010	21.001
7	39.6 MW	7.876	1.067	0.491	0.168	0.058	0.055	0.010	0.009	0.005	9.738
9	27 MW	5.370	0.727	0.335	0.115	0.039	0.037	0.007	0.006	0.003	6.640
15	9 MW	1.790	0.242	0.112	0.038	0.013	0.012	0.002	0.002	0.001	2.213
13	3.5 MW	0.696	0.094	0.043	0.015	0.005	0.005	0.001	0.001	< 0.001	0.861
17	1.13 MW	0.225	0.030	0.014	0.005	0.002	0.002	< 0.001	< 0.001	< 0.001	0.278

Baseline Emissions (Mg/yr) -- Average Emission Factor

MODEL TURBINE		FORMALDEHYDE	TOLUENE	ACETALDEHYDE	XYLENES	ETHYLBENZENE	BENZENE	PAHS	ACROLEIN	NAPHTHALENE	TOTAL HAPS
2	170 MW	4.297	0.856	0.550	0.277	0.247	0.062	0.013	0.033	0.009	6.344
1	85.4 MW	2.159	0.430	0.276	0.139	0.124	0.031	0.007	0.017	0.004	3.187
7	39.6 MW	1.001	0.199	0.128	0.064	0.058	0.014	0.003	0.008	0.002	1.478
9	27 MW	0.682	0.136	0.087	0.044	0.039	0.010	0.002	0.005	0.001	1.008
15	9 MW	0.227	0.045	0.029	0.015	0.013	0.003	0.001	0.002	< 0.001	0.336
13	3.5 MW	0.088	0.018	0.011	0.006	0.005	0.001	< 0.001	0.001	< 0.001	0.131
17	1.13 MW	0.029	0.006	0.004	0.002	0.002	< 0.001	< 0.001	< 0.001	< 0.001	0.042

overstated in the case where the highest emission factor from all the tests is used for each HAP;

3. HAP emissions may be different for combustion turbines using fuels other than natural gas;

4. HAP emission factors used in this base case analysis may overestimate HAP emissions for uncontrolled turbines, since a significant portion of the emissions tests in the ICCR Emissions Database for natural gas-fired turbines were conducted on units that use steam or water injection to reduce NOx emissions, and steam or water injection may result in increased HAP emissions due to the cooling of the combustion process;

5. For some pollutants there are very few emissions test reports available. In those cases where emission averages rely on very few tests, it is unclear whether the resulting emission factor is representative of the turbine population; and

6. The baseline emissions included in this analysis may underestimate annual HAP emissions from turbines that operate at less than 80% load, since the emission factors included in this base case analysis do not include the higher emission rates that may occur when turbines are operated at low loads.

IV. OXIDATION CATALYST COSTS

The costs of acquiring, installing, and operating oxidation catalysts for HAPs reduction on combustion turbines were obtained from the following sources:

- Quotes provided to EPA by catalyst vendors;
- Costs gathered by the Gas Research Institute (GRI); and
- Estimates provided by stakeholders.

The methodology to estimate the total annual costs for oxidation catalysts was obtained from the EPA “OAQPS Control Cost Manual” (EPA, 1990). The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. The GRI study (Ferry et al., 1998) also relied on the OAQPS methodology.

The OAQPS cost manual requires direct cost inputs for certain key elements, such as control device capital costs, and then relies on default assumptions (percentages of the direct cost inputs) to estimate other costs, such as installation. The following sections describe the direct cost inputs into the OAQPS methodology and the costs estimated using the OAQPS default assumptions. A printout of the spreadsheet used to estimate costs is presented as Appendix E.

The OAQPS manual uses five cost categories to describe the annual incremental cost incurred by installing a control device, such as an oxidation catalyst:

- **Purchased Equipment Costs (PEC)** include the capital cost of the catalyst and auxiliary equipment, and the cost of instrumentation, sales tax, and freight;

- **Direct Costs for Installation (DCI)** are the construction-related costs associated with installing the catalyst;

- **Indirect Costs for Installation (ICI)** include expenses related to engineering and start up;

- **Direct Annual Costs (DAC)** include catalyst replacement and disposal costs and the annual increases in utilities and operating and maintenance costs; and

- **Indirect Annual Costs (IAC)** are the annualized cost of the catalyst system and costs due to tax, overhead, insurance and administrative burdens.

The cost used in the cost-effectiveness calculation is the total annual cost, which is the sum of the DAC and IAC.

A. Cost Inputs

Cost estimates were developed for the following inputs:

- Capital cost of the oxidation catalysts;
- Capital cost of the catalyst housing;
- Contingency for capital costs;
- Catalyst life and equipment life;
- Catalyst disposal costs;
- Interest rate for capital recovery;
- Direct annual operating & maintenance costs;
- Fuel penalty costs; and
- Annual compliance test costs.

A description of the each cost input is provided below.

Capital cost of the oxidation catalysts

Cost estimates from Engelhard, a catalyst vendor, were used for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec to estimate the capital cost of the oxidation catalysts. The Engelhard costs were based on an oxidation catalyst that would achieve 90% CO conversion efficiency and 1” pressure drop across the catalyst panels (not total system pressure drop) and include the cost of an internal support frame and catalyst modules. Regression analysis on these cost data provided by the vendor suggested that there is a nearly linear relationship between catalyst cost and exhaust flow rate ($r^2 = 0.993$, when Catalyst cost=1541.8*(lb/sec)+102370). Catalyst costs were estimated for the seven model turbines using this equation, based on the Engelhard cost quotes, where cost is a function of turbine exhaust flow. Additional cost information is discussed in complicating factors.

Capital cost of the catalyst housing

The capital cost of the catalyst housing was estimated as 30% of the total cost of the catalyst system (the catalyst plus housing). This estimate is based on estimates provided orally by catalyst vendors.

Contingency

A contingency of 10% of the sum of the purchased equipment costs, direct costs of installation, and indirect costs of installation was incorporated in the base case analysis. The budgeted contingency would cover costs associated with equipment redesign and modifications, cost escalations, and delays in start-up. The OAQPS Control Cost Manual recommends a 3% contingency. However, a contingency of at least 10 percent is considered more appropriate for the base case analysis since the analysis is based on a preliminary vendor quote, not a guaranteed quote.

Catalyst life and equipment life

For the base case, the lifetime of purchased equipment was assumed to be fifteen years, except for the catalyst. Two scenarios were used for the catalyst life: the vendor guaranteed life (three years) and the “typical” life (six years) reported by catalyst vendors and users. The guaranteed life of the catalyst was used by EPA in the cost-effectiveness analysis for a passive catalytic device (non-selective catalytic reduction, NSCR) in the Alternative Control Techniques (ACT) document for reciprocating internal combustion engines (EPA, 1993b). In the Turbine ACT document, EPA used 5 years as the catalyst life for Selective Catalytic Reduction (SCR) (EPA, 1993a). The Turbine ACT did not specify whether the catalyst life was guaranteed life or "typical" life for SCR. However, in general, EPA prefers to rely on the useful life of equipment for cost-effectiveness calculations. The base case evaluates the costs using both the guaranteed life and the typical life to account for the uncertainty regarding the long-term performance of oxidation catalysts. Further discussion of the issues related to catalyst life are discussed as complicating factors.

The cost of catalyst replacement is annualized by applying a capital recovery factor based on the catalyst lifetime and interest rate to the cost of the oxidation catalyst only (based on the Engelhard formula).

Catalyst Disposal Costs

For the base case analysis, costs for catalyst disposal were limited to the freight charge associated with shipping the spent modules back to the vendor.

Interest Rate for Capital Recovery

An interest rate of 7 percent was used in the base case to calculate capital recovery.

Direct annual operating and maintenance costs

Operating labor costs were estimated using a factor of $25 per hour operating labor and an estimate of two hours per day incremental labor. The labor costs cover costs for operator duties likely to result from installing an oxidation catalyst and complying with MACT. Those duties include 1) inspection of the continuous parameter monitoring device, 2) collection and review of continuous parameter monitoring data, 3) inspection of the control device, and 4) recordkeeping and reporting assumed to be required by the MACT standard. In developing the labor estimates, the EPA estimates for labor for NSCR for reciprocating internal combustion engines and for SCR for turbines included in the Alternative Control Techniques (ACT) documents (EPA, 1993a and 1993b) were reviewed. The labor estimates for NSCR would more closely approximate the labor associated with an oxidation catalyst, since NSCR is essentially a passive catalytic device, like oxidation catalysts. The labor costs for SCR for turbines would be greater than the labor costs for oxidation catalysts, since SCR may require frequent inspection and adjustment of the ammonia feed system. Maintenance costs, including labor and materials, were estimated as 10% of the total purchased equipment cost, based on the ACT formula for NSCR. Maintenance costs cover catalyst washing (with water), maintenance of monitoring equipment, and labor for catalyst replacement (including removal and return of old catalyst and installation of replacement).

Fuel penalty costs

Increased pressure drop in the exhaust of a gas turbine will impact both heat rate and power output. For the base case analysis, fuel penalty costs are included to compensate for the increased heat rate as a result of the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a heat rate increase of 0.105% per inch of pressure drop (measured in inches of water column) and estimates of $2 per MMBtu and a 9,000 Btu/hp-hr baseline. The heat rate increase of 0.105% was drawn from the GRI study. The 0.105% is a very low estimate of the heat rate increase anticipated and most turbines would have higher increased heat rate due to backpressure from the catalyst. Other estimates of the heat rate increase are discussed in the complicating factors portion of this section. The estimate of $2 per MMBtu for natural gas was drawn from the GRI study. This estimate is low compared to market value of natural gas at this time. The estimate of increased exhaust backpressure on the turbine from the catalyst was based on an assumption that the total pressure drop associated with the catalyst system is solely the pressure drop across the catalyst panels. The total pressure drop would be higher than the pressure drop across the catalyst panels due to the pressure drop associated with the inlet and outlet ductwork for the catalyst system. Therefore, the increase in the exhaust backpressure and, therefore, the fuel penalty costs resulting from the increase in exhaust backpressure are understated in the base case analysis.

The Turbine World Handbook indicates that exhaust backpressure may result in a loss of power. The costs for loss of power were not included in the base case quantitative analysis. These costs would increase the cost of control beyond the base case costs presented in this paper. The costs for loss of power are discussed in the complicating factors portion of this section.

Annual Compliance Test Costs

Costs to perform one annual emissions compliance test are included in the base case. The costs for this annual test are estimated at $5,000. The costs were estimated based on an assumption that no continuous emissions monitoring data would be required in a MACT standard for combustion turbines. Instead, it was assumed that the MACT would require continuous monitoring for an operating parameter, such as temperature at the catalyst, along with an annual emissions test. The costs also were based on an assumption that a surrogate criteria pollutant can be measured and that HAPs would not be speciated.

B. Costs Estimated by OAQPS Control Cost Manual

The methodology outlined in the OAQPS Control Cost manual was used to estimate costs for the following:

- Capital cost for instrumentation (continuous parameter monitor);
- Sales tax for equipment purchases;
- Freight for equipment purchases;
- Direct installation costs (DCI), including foundations & supports, handling & erection, electrical, piping, insulation for ductwork, and painting;
- Indirect installation costs (ICI), including engineering, construction and field expenses, contractor fees, start-up, and performance tests; and
- Indirect annual costs (IAC), including annualized equipment costs, overhead, administrative costs, property taxes, and insurance.

A description of the methodology to estimate these costs is provided below.

Costs for instrumentation, taxes and freight are estimated by applying factors from the OAQPS cost manual to the capital cost of the catalyst and auxiliary equipment. These costs (catalyst capital cost, instrumentation, taxes, and freight) are then summed to estimate the total Purchased Equipment Costs (PEC). The components of the DCI (foundations and supports, erection and handling, electrical work, piping, painting and insulation) are then calculated by applying OAQPS cost manual factors to the PEC. Likewise, the components of the ICI (engineering, construction and field expenses, contractor fees, start-up, and initial performance test) are also calculated by applying factors to the PEC.

Indirect Annual Costs (IAC) are the annualized cost of the catalyst housing and the costs for overhead, administrative tasks, property taxes, and insurance. The equipment costs are annualized by applying a capital recovery factor (based on the equipment life, 15 years, and interest rate) to the sum of the direct and the indirect equipment costs, excluding the cost of the catalyst modules. The cost of the catalyst modules is considered a direct annual cost (DAC), and is annualized separately. Factors applied to the sum of the direct and indirect equipment costs (including contingency) are used to estimate the overhead, administrative costs, property taxes, and insurance.

C. Summary of Base Case Cost Estimates

Table 3 presents the range of costs estimated for the seven model turbines included in the base case cost-effectiveness analysis. The costs for each model turbine are presented in Appendix E. The highest annual costs are for the largest model turbine and the lowest annual costs are for the smallest model. The $/MW are lower for the larger model turbines and higher for the smaller model turbines.

Table 3. Range of Costs Estimated for Seven Model Turbines

Cost Category	Costs for 3-Year Catalyst Life*		Costs for 6-Year Catalyst Life*	
Total Capital Cost	$360,000 -	$4,800,000	$360,000 -	$4,800,000
Direct Annual Cost	$96,000 -	$980,000	$74,000 -	$680,000
Indirect Annual Cost	$65,000 -	$700,000	$65,000 -	$700,000
Total Annual Costs (DAC + IAC)	$160,000 -	$1,700,000	$140,000 -	$1,400,000

*Costs are rounded.

D. Complicating Factors

This section presents factors that complicate the estimation of the costs of acquisition, installation, and operation of oxidation catalyst on combustion turbines. For discussion, these complicating factors are divided into five categories:

- factors related to the cost of acquiring the oxidation catalyst;
- costs associated with site installation complications;
- costs associated with performance testing;
- complicating factors associated with increased exhaust backpressure; and
- costs associated with compliance monitoring.

Factors Complicating the Estimation of Catalyst Acquisition Costs

The catalyst costs used in this base case analysis are based on a formula that was derived from one vendor's cost quotes for six different sizes of combustion turbines. The vendor's cost quotes covered a range of turbine sizes that is similar to the turbine sizes represented in the seven model turbines used in this cost-effectiveness analysis. Exhaust flow rates for the vendor's cost quotes ranged from 28.4 lb/sec to 984 lb/sec, while exhaust flow rates for the seven model turbines ranged from 14.2 lb/sec to 986 lb/sec. The formula developed for this cost-effectiveness analysis represents a necessary simplification of the vendor's cost quotes to facilitate estimating costs for the seven model turbines used in this analysis.

Cost estimates for oxidation catalysts were available from two other sources: 1) cost estimates provided by General Electric (Schorr, 1998), and 2) cost estimates included in the GRI cost study (Ferry et al., 1998). Cost estimates were provided by General Electric for two large turbines (exhaust flow rates of 400 lb/sec and 1200 lb/sec). The formula calculated using the General Electric cost estimates is (0.85*(568.75*Exhaust Flow Rate (lb/hr) +172,500). For small turbines, the costs estimated using the General Electric formula are higher than the costs used in this base case analysis. For example, the General Electric formula estimates $153,490 for the catalyst for a 1.13 MW turbine, while the costs used in this base case analysis are $105,624. For a 3.5 MW turbine, the costs are similar, $166,446 estimated using the General Electric formula and $165,584 used in this analysis. For larger turbines, the costs estimated using the General Electric formula are lower than the costs used in this base case analysis. The differences in the costs estimated using the two different approaches increase with turbine size. For the 170 MW turbine, the General Electric formula estimates the cost of the catalyst as $623,294, while $1,622,585 was used in this cost-effectiveness analysis. [Note: the quote provided by Engelhard for a 170 MW turbine, exhaust flow 984.0lb/sec was $1,550,000.] The General Electric cost estimates were not used for this base case analysis for the following reasons: 1) cost estimates were provided only for two large turbines, and 2) the costs seemed to underestimate the costs when compared with the quotes received directly from a catalyst vendor.

The cost estimates included in the GRI study were also reviewed. In that case, GRI used cost quotes provided by two catalyst vendors for a 6,000 horsepower turbine. Vendors provided cost quotes for a range of VOC control estimates: 95 percent, 50 percent, 35 percent, and 22 percent. In comparing the cost quote in the GRI study for 95 percent VOC control and 98 percent CO control, the costs were similar to the costs for a 6,000 hp turbine estimated using the formula in this base case (assuming 90 percent CO control) -- $204,500 in the GRI study, and $206,796 using the base case formula. The GRI costs were not used for this analysis because there was insufficient information to develop a reliable cost formula that could be applied to a wide range of turbine models, ranging in size from 1.13 MW to 170 MW.

The vendor quotes that have been obtained are essentially for CO oxidation catalysts. As noted above, available emissions data indicates that CO/VOC oxidation catalysts should reduce organic HAP compounds. However, the ICCR Coordinating Committee is not aware of any actual industry experience in the acquisition of an oxidation catalyst specified to achieve a percentage reduction of formaldehyde, or the other HAPs. In the absence of such experience, the cost estimate for an oxidation catalyst designed to reduce organic HAPs from combustion turbines is uncertain. Uncertainty about the estimated cost for a HAP reduction catalyst is increased when considering that oxidation catalysts would be required for fuels other than natural gas. Oxidation catalysts for oil fired turbines may have to be formulated differently than for gas fired turbines, and may have different lifetime and degradation characteristics.

Another key uncertainty in estimating oxidation catalysts costs is the assumption regarding catalyst life. Clearly, a catalyst that can be relied upon to function for many years will have lower annual costs than a catalyst that must be replaced more often. The issue of catalyst lifetime includes estimating the probability of complete failure of the catalyst, and also estimating the degradation of catalyst performance over time.

There may be a difference between the expected useful life of an oxidation catalyst, and the period of the vendor's performance guarantee. This raises the question of which period should be used in calculating cost-effectiveness. As noted in another section, a number of cost-effectiveness estimates based on different assumptions about catalyst life and performance are presented.

Limited information was available on the life of the catalyst. Information from an emissions test conducted by GRI on a ten-year-old CO oxidation catalyst indicates that performance can degrade when the catalyst is used for an extended period of time (10 years in that case). The GRI test is described under Section V of this paper. Further information is not available that would allow an estimate of the expected rate of oxidation catalyst performance degradation, or the effect of maintenance (such as catalyst washing) on catalyst life. According to catalyst vendors, the degradation of catalyst performance over time is not linear.

Costs associated with site installation complications

Costs for retrofit complications were not available for the base case analysis. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. One stakeholder provided retrofit costs for adding a catalyst system to an ABB Type 11 gas turbine (gas flow = 580 lb/sec) (Allen, 1998a and 1998b). The retrofit costs totaled about $800,000, including $100,000 for ductwork. The cost of down time is also site specific. In the case described above, the cost cited for down time was about $3.5 million based on a 35 day outage, a power sales price of $35/MWh, and a steam cost $4.5/thousand pounds of steam (Allen, 1998a).

Costs Associated with Performance Testing

Costs for performance testing were included in the base case quantitative analysis in accordance with the OAQPS Control Cost Manual. The costs for performance testing are estimated as 0.01% of the Purchased Equipment Costs (PEC). For the 170 MW turbine, $27,000 was calculated as the performance test costs using the OAQPS formula. For the 1.13 MW turbine, $2,095 was calculated as the performance test costs using the OAQPS formula. The costs for stack emissions testing would be fixed, regardless of turbine size. The costs estimated for performance testing may have been underestimated for the base case analysis, especially for the small model turbines.

Complicating Factors Associated with Increased Exhaust Backpressure

For the base case quantitative analysis, fuel penalty costs were estimated assuming a 0.105% heat rate increase per inch of pressure resulting from installation of a catalyst system. The 0.105% is a very low estimate of the heat rate increase. The Gas Turbine World 1997 Handbook provides rough rule of thumb estimates of heat rate increase and power loss per inch pressure drop (Gas Turbine World 1997). For aeroderivative turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.7% (0.175% per inch) and reduce power output 0.7%. For heavy frame turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.6% (0.15% per inch) and reduce power output 0.6%. Therefore, the heat rate increase due to increased pressure drop is understated in the base case analysis.

To estimate pressure drop for the base case quantitative analysis, it was assumed that the total pressure drop associated with the catalyst system is solely the pressure drop across the panels. The total pressure drop would be higher than the pressure drop across the catalyst panels alone due to the inlet and outlet ductwork. Therefore, the operating costs associated with the increase in exhaust backpressure are understated in the base case analysis. The fuel penalty costs associated with backpressure may be significantly higher when a more realistic estimate of the catalyst system pressure drop is used.

In addition, implementing oxidation catalyst control may result in a reduction in turbine power output caused by increased exhaust backpressure on the engine. The costs associated with the power loss depend on site-specific factors (e.g., value of lost product or capital and annual costs for equipment required to make up for the power loss). The increase in exhaust backpressure results in a loss of power sales if the unit is operating at full load. One stakeholder provided information on the loss in annual sales at different selling prices for electrical power (Allen, 1998b). For a GE Frame 7 turbine, the annual cost (i.e., lost sales) per inch of water pressure drop may be estimated using the following equation:

$$\text{Annual Cost (\$/inch)} = 1{,}160 * \text{Power Value (\$/MWh)} + 100$$

For this example turbine unit, if electricity can be sold for $40 per MWh, the annual cost per each additional inch of water pressure drop caused by the catalyst would equal $46,500.

These costs were not incorporated into the base case analysis. The cost associated with power loss would increase the costs for the control system.

Costs Associated with Compliance Monitoring

If the MACT would require speciated HAP emissions test data, the costs for the annual compliance test would increase significantly. Also, if compliance tests must be conducted more frequently than annually, the costs would increase.

V. PERFORMANCE OF OXIDATION CATALYSTS IN REDUCING HAP EMISSIONS

Oxidation catalysts have been installed on combustion turbines for the purposes of controlling emissions of carbon monoxide (CO) and some volatile organic compounds (VOC). The catalyst is designed to promote the oxidation of hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O). It is expected that existing catalysts similar to those in use for CO and VOC control may oxidize organic HAPs.

In order to estimate the quantitative performance of an oxidation catalyst two emissions test reports were evaluated and engineering estimates of potential oxidation catalyst performance were reviewed.

A. HAP Emissions Test Data for Oxidation Catalysts

At present, no HAP emissions tests in the ICCR Emissions Database include before and after testing of a combustion turbine with an oxidation catalyst. Emissions test data on the performance of oxidation catalysts should be collected.

Two existing emission test reports that provide some information on the performance of oxidation catalysts in reducing HAP emissions were identified. The two emission tests are still being evaluated and may be included in the database after review. One test was conducted by the Gas Research Institute(GRI), in cooperation with the American Petroleum Institute (API) and Southern California Gas (SoCal), in March 1998, on a combustion turbine using a passive oxidation catalyst system, similar to the catalyst used for this base case cost-effectiveness evaluation. A summary of this test has been provided and the complete test data will be provided to EPA when it is available (Gundappa, 1998). The complete test report will have to undergo review prior to being included in the ICCR Emissions Database. The oxidation catalyst installed on this turbine is a precious metal catalyst, similar to the catalyst technology used as the basis for this cost-effectiveness analysis. This type of oxidation catalyst may be used over a temperature range of 450°F to 1500°F (Chen et al., 1993).

The second test was submitted to EPA for a new catalytic oxidation control system, called SCONOx™ (Bell and Finken, 1997). Although the SCONOx™ system relies on oxidation to reduce hydrocarbons, such as CO, or HAPs, such as formaldehyde, the SCONOx™ catalyst is a more complicated control system than the oxidation catalyst used for this base case cost-effectiveness evaluation. SCONOx™ may be operated over a temperature range of 300°F to 700°F (Goal Line Environmental Technologies, LLC). The cost and cost-effectiveness values presented in this paper were not based on costs for the SCONOx™ system. A description of the SCONOx™ system is provided in Appendix F. The results from these two emissions tests are discussed below.

GRI/API/SoCal Test

The GRI/API/SoCal testing was conducted in March 1998. GRI, API, and SoCal added the emissions test to an existing emissions testing program in order to provide on the performance of oxidation catalysts. The test was performed on a 20 MW GE LM2500 turbine equipped with a Johnson Matthey CO oxidation catalyst. Three load conditions were tested, including full load (typical) and part loads (88% and 70% of rated load). Concentrations of HAPs, including formaldehyde, were measured before and after the oxidation catalyst. HAP and CO measurements were conducted with Fourier transform infrared (FTIR) sampling upstream and downstream of the oxidation catalyst. Aldehydes also were measured with the California Air Resources Board (CARB) Method 430, which relies on an aqueous 2,4-Dinitrophenylhydrazine solution. Complete results of the test were not available in time to incorporate them into the ICCR Emissions Database. However, a summary of the results was provided (Gundappa, 1998). Based on FTIR, formaldehyde emissions upstream of the catalyst were in the approximate range of 400 to 460 parts per billion by volume (ppbv) and CO emissions upstream of the catalyst were in the range of 10 to 17 parts per million by volume (ppmv). Both formaldehyde and CO emissions increased as the load decreased. With FTIR, the reduction in emissions across the oxidation catalyst was on the order of 10 to 30 percent for formaldehyde and 25 to 33 percent for CO, with the highest reduction at the lowest load condition. CARB 430 results did not agree with the FTIR data. In some cases, the CARB 430 results indicated that levels of aldehydes (formaldehyde and acetaldehyde) increased after the catalyst.

SCONOx™ Test

A unit equipped with a SCONOx™ catalyst system was tested on March 14, 1997, by Delta Air Quality Services (Bell and Finken, 1997). Samples were collected at the inlet to the catalyst and at the exhaust from the cogeneration unit (turbine exhaust stack) and analyzed for the following three HAPs: formaldehyde, acetaldehyde, and benzene. Formaldehyde and acetaldehyde reportedly were reduced by 97% and 94%, respectively, based on the catalyst inlet and turbine exhaust concentrations. No conclusion regarding the control efficiency for benzene could be drawn since the levels before and after the catalyst were both very low and within 0.05 parts per billion of each other.

The SCONOx™ report was reviewed in greater detail to determine if the data from this test should be included in the emissions database. The accuracy of the catalyst inlet concentrations measured during the test was questioned since isokinetic sampling was not conducted nor was a multi-point probe used to collect the samples. However, the catalyst inlet concentrations were consistent with other source tests involving the same model turbine (GE LM 2500), using water injection. Also, even if the catalyst inlet concentrations were one-half to one-third of the average concentration measured during the source test, the efficiency of the SCONOx™ would still exceed 90% for formaldehyde. Therefore, the ICCR Coordinating Committee recommends inclusion of the data from this test in the emissions database, with the caveat that EPA may want to retest this unit to address some of the concerns identified during review of the test.

Based on a review of the two emissions tests available, the ICCR Coordinating Committee concludes that organic HAPs, such as formaldehyde and acetaldehyde, may be reduced using after-treatment controls that rely on catalytic oxidation. The Committee also concludes that, in some cases, a high percent reduction may be possible for certain pollutants. However, the Committee notes that the limited data available is not sufficient to draw conclusions about the achievability of high emission reductions over the life of catalytic devices. In addition, the Committee notes that although there is some data that suggests catalysts degrade over time, the rate and the extent of the degradation cannot be determined based on the limited data.

B. Engineering Estimates of HAP Reduction Performance for Oxidation Catalysts

The ICCR Coordinating Committee reviewed information available in the literature on the HAP reduction performance of oxidation catalysts on organic HAPs, such as formaldehyde. In particular, an article prepared by Engelhard, the catalyst vendor that supplied the cost quotes for this base case cost-effectiveness analysis (Chen et al., 1993), was reviewed. In the article, Engelhard notes that oxidation catalysts for combustion turbines are typically designed to achieve between 80 and 95 percent CO removal. In addition, the article indicates the conversion level for each species of hydrocarbon will depend on its diffusion rate in the exhaust gas. In general, larger, heavier molecules will diffuse more slowly than smaller, lighter molecules. As the size of the hydrocarbon molecule increases, hydrocarbon conversion decreases due to decreased gas diffusivity. According to the article, an oxidation catalyst designed for 90 percent CO removal will achieve 77 percent reduction of formaldehyde, 72 percent reduction of benzene, and 71 percent reduction of toluene. The article notes that the relative conversion rates do not depend on geometry and that reduction for molecules larger than formaldehyde will be lower than rates achievable for formaldehyde.

C. Summary of Base Case Performance Estimate

Two performance values for the base case cost-effectiveness analysis -- 80 percent emissions reduction and 50 percent emissions reduction is used in the analysis; 80 percent emissions reduction is used for both the 3-year and 6-year catalyst life assumptions and 50 percent emissions reduction is evaluated for a 6-year catalyst life.

These levels of reduction represent appropriate levels of reduction for the base case cost-effectiveness analysis, covering both high and moderate levels of emission reduction. The Engelhard article serves as the basis for the 80% reduction as the catalyst performance in the base case analysis (77% rounded up to 80%). Although the Engelhard article indicates that emission reductions for larger molecules, such as PAHs, may be less than the reduction achieved for formaldehyde, the HAP reduction performance for the base case analysis was set to 80 percent for all pollutants. The 50% reduction was chosen as a moderate level of emission reduction to examine the sensitivity of the cost-effectiveness to any significant degradation of the catalyst performance that might occur over time. Additional emissions test data before and after oxidation catalysts would be necessary to determine whether the levels of reductions are achievable for combustion turbines, considering the full range of operating conditions and catalyst degradation.

The emission reductions achieved for each model turbine assuming 80 percent reduction and 50 percent reduction are presented in Tables 4 and 5.

D. Complicating Factors

This section presents several factors that complicate the estimation of the performance of oxidation catalysts in the reduction of organic HAP in the exhaust of combustion turbines.

Uncertainty About the Real World Performance of Oxidation Catalysts for HAPs

As noted earlier, although there are oxidation catalysts installed on existing turbines for control of CO and some VOCs, there are not conclusive emissions data available regarding the HAP reduction performance of those oxidation catalysts over time. CO catalysts systems in use operate on far higher levels of CO than the expected concentration of HAPs. The cost-effectiveness estimates used for this base case analysis are derived from engineering judgement rather than actual data. It is possible that it may be more difficult than anticipated to achieve a consistent 80% reduction of HAPs across a

Table 4. Emissions Reductions for Each Model Turbine Assuming 80% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 80% HAPs Reduction Performance

Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	27.048	3.664	1.687	0.579	0.198	0.189	0.035	0.029	0.016	33.445
1	85.4 MW	13.587	1.841	0.848	0.291	0.099	0.095	0.018	0.015	0.008	16.801
7	39.6 MW	6.301	0.854	0.393	0.135	0.046	0.044	0.008	0.007	0.004	7.791
9	27 MW	4.296	0.582	0.268	0.092	0.031	0.030	0.006	0.005	0.003	5.312
15	9 MW	1.432	0.194	0.089	0.031	0.010	0.010	0.002	0.002	0.001	1.771
13	3.5 MW	0.557	0.075	0.035	0.012	0.004	0.004	0.001	0.001	< 0.001	0.689
17	1.13 MW	0.180	0.024	0.011	0.004	0.001	0.001	< 0.001	< 0.001	< 0.001	0.222

Emissions Reductions (Mg/yr)-- Average Emission Factor -- 80% HAPs Reduction Performance

Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	3.438	0.685	0.440	0.221	0.198	0.050	0.011	0.026	0.007	5.075
1	85.4 MW	1.727	0.344	0.221	0.111	0.099	0.025	0.005	0.013	0.004	2.549
7	39.6 MW	0.801	0.159	0.102	0.052	0.046	0.012	0.003	0.006	0.002	1.182
9	27 MW	0.546	0.109	0.070	0.035	0.031	0.008	0.002	0.004	0.001	0.806
15	9 MW	0.182	0.036	0.023	0.012	0.010	0.003	0.001	0.001	< 0.001	0.269
13	3.5 MW	0.071	0.014	0.009	0.005	0.004	0.001	< 0.001	0.001	< 0.001	0.104
17	1.13 MW	0.023	0.005	0.003	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.034

Table 5. Emissions Reductions for Each Model Turbine Assuming 50% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 50% Reduction Performance											
MODEL TURBINE		FORMALDEHYDE	TOLUENE	ACETALDEHYDE	XYLENES	ETHYLBENZENE	BENZENE	PAHS	ACROLEIN	NAPHTHALENE	TOTAL HAPS
2	170 MW	16.905	2.290	1.055	0.362	0.124	0.118	0.022	0.018	0.010	20.903
1	85.4 MW	8.492	1.150	0.530	0.182	0.062	0.059	0.011	0.009	0.005	10.501
7	39.6 MW	3.938	0.533	0.246	0.084	0.029	0.027	0.005	0.004	0.002	4.869
9	27 MW	2.685	0.364	0.168	0.057	0.020	0.019	0.004	0.003	0.002	3.320
15	9 MW	0.895	0.121	0.056	0.019	0.007	0.006	0.001	0.001	0.001	1.107
13	3.5 MW	0.348	0.047	0.022	0.007	0.003	0.002	< 0.001	< 0.001	< 0.001	0.430
17	1.13 MW	0.112	0.015	0.007	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	0.139
Emissions Reductions (Mg/yr)-- Average Emission Factor -- 50% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	2.149	0.428	0.275	0.138	0.124	0.031	0.007	0.017	0.004	3.172
1	85.4 MW	1.079	0.215	0.138	0.069	0.062	0.016	0.003	0.008	0.002	1.593
7	39.6 MW	0.500	0.100	0.064	0.032	0.029	0.007	0.002	0.004	0.001	0.739
9	27 MW	0.341	0.068	0.044	0.022	0.020	0.005	0.001	0.003	0.001	0.504
15	9 MW	0.114	0.023	0.015	0.007	0.007	0.002	< 0.001	0.001	< 0.001	0.168
13	3.5 MW	0.044	0.009	0.006	0.003	0.003	0.001	< 0.001	< 0.001	< 0.001	0.065
17	1.13 MW	0.014	0.003	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.021

real world population of combustion turbines running under various ambient conditions and operating points.

Differential Performance for Various HAPs

The assumption used in this base case analysis that oxidation catalysts will have the same HAP reduction performance for all organic HAPs was necessary because there was insufficient emissions data to estimate HAP reduction performance for specific species of HAPs. This assumption is incorrect, based on engineering estimates performed by Engelhard, a catalyst vendor (Chen et al., 1993). Engelhard indicates that individual HAPs will be oxidized at different rates due to differences in the size of the hydrocarbons and that the HAP reduction performance for each HAP will depend on its diffusion rate. In general, larger, heavier molecules (like PAHs) will diffuse more slowly than smaller, lighter molecules (like CO).

The assumptions used in this base case analysis tend to overestimate HAP reduction efficiencies for HAPs other than formaldehyde, especially HAPs like PAHs that are larger, heavier molecules.

Decreased Catalyst Performance Over Time

This effect was discussed as a part of the evaluation of catalyst life for costing purposes. A decline in catalytic activity also would impact the performance side of the equation in that fewer metric tons of HAPs would be removed from the turbine exhaust.

VI. COST-EFFECTIVENESS RESULTS

A breakdown of the total HAP reductions achieved for individual pollutants is provided in Tables 4 and 5. The cost-effectiveness values based on total HAP reductions are presented in Table 6 for each model turbine**.** The cost-effectiveness for total HAPs is provided to more fully demonstrate the benefit achieved in terms of total reduction of HAPs for the costs required to install oxidation catalysts. Cost-effectiveness for individual HAPs, calculated as the total annual

Table 6. Cost-Effectiveness Estimated for Each Model Turbine -- Base Case Analysis

	Cost Effectiveness ($/Mg Total HAPs Reductions*)					
	Highest EF			Average EF		
Model Plant	3-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 50% Emissions Reduction	3-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 50% Emissions Reduction
Model 1 -- 85.4 MW Turbine	$69,000	$57,000	$91,000	$450,000	$380,000	$600,000
Model 2 -- 170 MW Turbine	$50,000	$41,000	$66,000	$330,000	$270,000	$440,000
Model 7 -- 39.6 MW Turbine	$81,000	$67,000	$110,000	$530,000	$440,000	$710,000
Model 9 -- 27 MW Turbine	$78,000	$66,000	$100,000	$520,000	$430,000	$690,000
Model 13 -- 3.5 MW Turbine	$290,000	$250,000	$400,000	$1,900,000	$1,700,000	$2,600,000
Model 15 -- 9 MW Turbine	$150,000	$130,000	$200,000	$1,000,000	$840,000	$1,400,000
Model 17 -- 1.13 MW Turbine	$730,000	$630,000	$1,000,000	$4,800,000	$4,100,000	$6,600,000

*Cost-effectiveness values were rounded. Annual costs estimated for each model turbine are presented in Appendix E. HAPs reductions estimated for each model turbine are presented in Tables 4 and 5. Cost-effectiveness values for individual HAPs are presented in Appendix G.

costs by the mass emissions for each individual HAP, is presented in Appendix G. The cost-effectiveness for individual HAPs is presented to show the cost-effectiveness sensitivity for individual HAPs.

In general, the cost per metric ton of reduced HAP emissions is higher for small turbines, because capital costs, on a per-megawatt basis, are highest for these units and the annual HAP emissions are low. The costs per metric ton also would increase for small and large turbines as operating hours decrease because capital costs remain unchanged while annual HAP emissions are lower.

VII. CONCLUSIONS AND RECOMMENDATIONS

The ICCR Coordinating Committee has assessed the various elements that are relevant to estimation of the cost-effectiveness of oxidation catalysts for control of organic HAPs emitted by combustion turbines. Based on this assessment the ICCR Coordinating Committee has reached the following conclusions.

1. Using a simplified base case, the annual costs associated with installation and operation of oxidation catalysts for the model turbines ranged from $160,000 for a 1.13 MW unit to $1,700,000 for a 170 MW unit, assuming a three-year catalyst life. Annual costs ranged from $140,000 for a 1.13 MW unit to $1,400,000 for a 170 MW unit, assuming a six-year catalyst life;

2. Based on quantified estimates of emissions, cost, and percent reduction for a simplified base case, the cost-effectiveness of oxidation catalysts for control of total HAPs from combustion turbines ranges from $41,000 per metric ton for a 170 MW unit to $1,000,000 per metric ton for a 1.13 MW unit, assuming emission rates based on the highest reported emission factors for all HAPs. The cost-effectiveness values range from $270,000 for a 170 MW unit to $6,600,000 for a 1.13 MW unit when the average emission factor is used; and

3. Because of a variety of complicating factors, it is likely that the base case cost-effectiveness estimated range is lower than the actual cost-effectiveness which would be exhibited by actual application of oxidation catalysts to most combustion turbines in the United States. Key complicating factors include the catalysts life, problems with retrofitting ducts and the catalyst housing at existing facilities, differential effectiveness of the catalysts on various HAP compounds, and fuels that require pre-treatment to avoid fouling the catalyst. In addition, there is uncertainty regarding the HAPs reduction performance included in this base case analysis due to the limited emissions test data available to predict the performance of oxidation catalyst in reducing organic HAP emissions from combustion turbines. While experience with CO oxidation catalysts is useful for evaluating the potential HAP reduction performance, there may be important differences between the costs

and performance of CO catalysts and the costs and performance of catalysts for reduction of organic HAPs.

Most of the complicating factors that have not been quantified in the numerical estimates would tend to increase the catalyst costs, or decrease catalyst performance. Because of this, the base case quantitative estimate reported in this paper is a lower range estimate of the cost-effectiveness of oxidation catalysts for HAPs control on combustion turbines.

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Appendix A

List of Model Turbines

Appendix A - List of Model Turbines

Model Plant	Unit	Operating Hours	Heat Recovery	Existing Application	Clean Fuel	Typical Applications	Surrogate	Output	Ex. Flow
1	Large	8000	Y	Y	Y	existing utility/IPP generating station	GE PG 7121EA	85.4	658
1A	Large	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 7121EA	85.4	658
1B	Large	8000	Y	Y	Y	existing utility/IPP generating station (duct burner)	GE PG 7121EA	85.4	658
2	Large	8000	Y	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
2A	Large	8000	Y	N	N	new unit with residual oil fuel	GE PG 7231FA	170	986
2B	Large	8000	Y	N	Y	new utility/IPP generating station (duct burner)	GE PG 7231FA	170	986
3	Large	2000	N	Y	Y	existing utility/IPP generating station	GE PG 7231FA	170	986
3A	Large	2000	N	Y	Y	existing utility/IPP station (space constrained)	GE PG 7231FA	170	986
4	Large	2000	N	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
5	Large	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 7121EA	85.4	658
6	Large	500	N	N	Y	new utility/IPP peaking unit	GE PG 7121EA	85.4	658
7	Medium	8000	Y	Y	Y	existing industrial power production	GE PG 6561B	39.6	318
7A	Medium	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 6561B	39.6	318
7B	Medium	8000	Y	Y	Y	existing industrial power production (duct burner)	GE PG 6561B	39.6	318
8	Medium	8000	Y	N	Y	new industrial power production	GE PG 6561B	39.6	318
8A	Medium	8000	Y	N	N	new unit with residual oil fuel	GE PG 6561B	39.6	318
8B	Medium	8000	Y	N	Y	new industrial power production (duct burner)	GE PG 6561B	39.6	318
9	Medium	8000	N	Y	Y	existing pipeline compressor/ ind.- mech. drive	GE LM2500	27	178
10	Medium	8000	N	N	Y	new pipeline compressor/ ind. mech. drive	GE LM2500	27	178
11	Medium	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 6561B	39.6	318
12	Medium	500	N	N	Y	new utility/IPP peaking unit	GE PG 6561B	39.6	318
13	Small	8000	Y	Y	Y	existing industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
13A	Small	8000	Y	Y	N	existing landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
13B	Small	8000	Y	Y	Y	existing ind. process plant (duct burner)	Solar Centaur 40	3.5	41
14	Small	8000	Y	N	Y	new industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
14A	Small	8000	Y	N	N	new landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
14B	Small	8000	Y	N	Y	new ind. process plant (duct burner)	Solar Centaur 40	3.5	41
15	Small	8000	N	Y	Y	existing pipeline compressor	Solar Mars T12000	9	83.6
15A	Small	8000	N	Y	Y	existing offshore platform (space constrained)	Solar Mars T12000	9	83.6
16	Small	8000	N	N	Y	new pipeline compressor/offshore platform	Solar Mars T12000	9	83.6
17	Small	200	N	Y	Y	existing emergency power (hospital,university,etc)	Solar Saturn T1500	1.13	14.2
18	Small	200	N	N	Y	new emergency power (hospital, university, etc)	Solar Saturn T1500	1.13	14.2

Appendix B

Description of ICCR Emissions Database

Appendix B - Description of ICCR Emissions Database

This memorandum provides a short description of the development of the emissions database for turbines, including assumptions used in the underlying calculations.

Development of the Emissions Database

The emission test reports were first carefully reviewed and summarized. Facility name, location, testing company, date of testing, make and model of turbine, manufacturer rating (and units), load, fuel type, application and control device (for emissions) were entered in a table named ?Facilities.? Pollutant name, sampling method, concentrations and units, detection limits and units, % oxygen, fuel factors, exhaust gas flow rates, stack temperature, fuel heating value and flow rate, % humidity, standard temperature, and pollutant molecular weight were entered in a table named ?Test Data.? Emission rates (lb/hr) and emission factors (lb/MMBtu) were also entered in that table for comparison with the emissions calculated in the database using the pollutant concentrations for each test run.

Test reports included in the database were identified using the following scheme: numbers from 1 to 99 were assigned to tests containing only hazardous air pollutants (HAPs), and numbers greater than 100 were allocated for tests with only criteria pollutants or with both HAPs and criteria pollutants. Exceptions are the reports numbered 10 and 15. These test reports contain both HAPs and criteria pollutant test results. They are numbered as HAPs-only type reports because criteria pollutant data were identified in these reports after the first version of the database. Test reports containing more than one turbine, multiple load conditions, different fuels, control device inlet and outlet samples (criteria pollutant data only), or more than three sampling runs were assigned the same initial number followed by an extension (for example, 1.1 or 1.1.1).

Some of the test reports in the database include an ?x? symbol at the end of the test report number (e.g., test report 8x). The ?x? symbol indicates that the test report does not meet the acceptance criteria. The data from these test reports are included in the database for informational purposes only.

Construction of database reports (i.e., summaries of relevant data) required the complete separation of tests with HAPs-only data from tests with only criteria pollutant data and tests with both HAPs and criteria pollutant data. The ?Test Data? table was consequently divided into three tables: ?Test Data - HAPs,? containing all HAP data in the Test Data table; ?Test Data - Criteria Pollutants,? containing all criteria pollutant data in the Test Data table, and ?Test Data - HAPs + Criteria,? containing the tests that include data for both HAPs and criteria pollutants.

In the report section, a set of 6 different reports was built for each of the test data tables discussed above. These reports provide information about pollutant concentrations (corrected to

15% O_2) and emissions in units of lb/hr, lb/MMBtu, and lb/MW-hr. Individual sets of reports were also developed for test summaries and pollutant summaries.

Treatment of non-detected or non-reported concentrations

Many pollutants, especially HAPs, were not detected in some or all of the sampling runs collected during a test. In these cases, concentrations were entered in the database as ?ND.? Although the test reports identified those pollutants not detected for a given testing run, the detection limit (DL) values were not always provided (i.e., ND was reported rather than a detection limit concentration). Often, review of the lab report and some additional calculations were necessary to determine the DL concentration. For example, in the case of formaldehyde, detection limits were usually given in micrograms or micrograms per milliliter in the lab report. Estimation of the DL in the same units as the test data (e.g., ppb) involved the use of the sample volume collected during the test and additional unit conversions (for example, micrograms/cubic meter to ppb).

Unfortunately, the DL could not always be found or calculated based on the laboratory report. Whenever a pollutant was not detected in all three runs and the DL could not be determined, the pollutant was removed from the database. This procedure was used for report ID #1 for benzene and chromium (VI). Also, due to the calculations discussed above, two or three different DLs (one per testing run) were determined for the same pollutant in some tests. The protocol followed in these cases was to take the highest DL value.

In some tests, only one or two runs were conducted, or runs were eliminated during test report preparation due to sampling problems encountered during the test. Missing runs were entered as NR (not reported) in the database. Other parameters missing from the test reports, such as exhaust gas flow rates, were also entered in the database as NR.

The acronym NA sometimes appears in the DL field. This acronym is used in those cases when a pollutant was measured above the detection limit in all of the testing runs but a detection limit value was not reported in the test report.

Equations

Using raw test data (i.e., lab-reported pollutant concentrations and stack test parameters), calculations were performed to estimate emissions in lb/hr, lb/MW-hr and lb/MMBtu. Modules, small programs written in Visual Basic code, were built to perform the calculations. There are various modules in the emissions database that perform different tasks, but only the main modules are described in this memorandum.

The equations used in the modules were taken from EPA sampling methods 19 and 20 in 40 CFR Part 60, Appendix A. For example, for the correction of the dry pollutant concentration to 15% O_2, Equation 20-4 from EPA method 20 is used:

$$C_{adj} = C_d * \frac{20.9 - 15}{20.9 - \% O_2}$$

where $\%O_2$ refers to the reported oxygen level during the testing and C_d to the pollutant dry concentration in ppb.

For the calculation of emission rates in lb/hr, lb/MW-hr, and lb/MMBtu, the following equations were used:

1. Pounds per hour:

When the concentration of pollutant is given in ppb :

$$M(lb/hr) = C_{ppb} * Q * 60 * \frac{MW}{T_{std} + 460} * 1.369x10^{-9}$$

Where C_{ppb} is the dry concentration of pollutant in ppb; Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; MW is the pollutant molecular weight (in lb/lb-mol); T_{std} is the standard temperature in degrees Fahrenheit used in the test report; 460 is the conversion factor from degrees Fahrenheit to degrees Rankine; and $1.369x10^{-9}$ is the conversion factor from ppb to pounds per cubic feet. The conversion factor from ppb to pounds per cubic feet was derived from 40 CFR, App. A, Meth. 20, page 1026.

When the concentration of a pollutant is given in units other than ppb or ppm, the equation is :

$$M(lb/hr) = C_p * Q * 60 * A$$

Where C_p is the concentration of pollutant in micrograms per dry cubic feet (ug/dscf), micrograms per dry cubic meter (ug/dscm), grams per dry cubic feet (g/dscf) or grams per dry cubic meter (g/dscm). For particulate matter, concentrations are in grains per dry cubic feet (gr/dscf), grains per dry cubic meter (gr/dscm), micrograins per dry cubic feet (ugr/dscf) and micrograins per dry cubic meter (ugr/dscm). Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; and A is a conversion factor from the given units to lb/dscf.

The values for A for the different units are:

1.1 For ug/dscf, A = $2.205\text{x}10^{-8}$

1.2 For ug/dscm, A = $6.24\text{x}10^{-10}$

1.3 For g/dscf and g/dscm, multiplying 1.1 and 1.2 by $1\text{x}10^{-6}$

1.4 For ugr/dscf, A = $1.43\text{x}10^{-10}$.

1.5 For ugr/dscm, A = $4.043\text{x}10^{-12}$.

1.6 For gr/dscf and gr/dscm, multiplying 1.4 and 1.5 by $1\text{x}10^{-6}$

2. Pounds per megawatt-hour:

The emission factor is calculated by dividing the emissions rate in lb/hr by the turbine rating during the test. The manufacturer rating and the test load are necessary data for this calculation. When load was not available, it was assumed to be 100%. The equation is :

$$M(lb/MW - hr) = \frac{M(lb/hr)}{\frac{R * L}{100}}$$

Where M(lb/hr) is the emission rate in lb/hr; R is the manufacturer rating for the turbine in MW; and L is the turbine testing load in %. The equation is:

3. Pounds per million Btu:

$$M(lb/MMBtu) = C_p * F * \frac{20.9}{20.9 - \% O_2} * B * \left(\frac{MW}{T_{std} + 460} \right)$$

Where C_p is the dry concentration of pollutant in any of the units already described for the calculation of emission factors (1.1 - 1.6); F is the fuel factor in dry standard cubic feet per minute per million Btu; the fraction 20.9/(20.9-%O_2) is an oxygen correction factor; and B is the conversion factor corresponding to the units in which the pollutant concentration is reported (see the units described in 1.1 - 1.6). The fraction MW/(T_{std}+460) is a conversion factor used only when the pollutant concentration was provided in ppb.

When the fuel factor or standard temperature was not available, defaults were used.

Defaults and Assumptions

For the estimation of emission factors from the concentrations given in ppb, gaseous pollutants were assumed to have ideal gas behavior, so that the volume occupied by an ideal gas (22.4 liters/mol) could be used for calculation of a conversion factor.

Not all of the reports contained the necessary information required for the calculation of emission factors. Important parameters are concentrations, units, detection limits, oxygen levels, exhaust gas flow rates, fuel factors, standard temperatures and molecular weights. In most cases, fuel factors and standard temperatures were missing. In some cases, exhaust gas flow rates were not provided in the report. Lack of gas flow rates still allows for the calculation of emission factors in pounds per million Btu. Consequently, tests lacking exhaust gas flow rates were kept in the database, but the emissions in pound per hour are shown as NR.

For non-methane hydrocarbons (NMHC) and total hydrocarbons (THC), a molecular weight of 16 (as methane) was assumed. Test reports in the database indicated a molecular weight of 16 for THC and, in most cases, for NMHC. However, in some test reports, the molecular weight chosen to report emission factors for NMHC was the molecular weight of hexane.

Fields with NR for fuel factors and standard temperatures were filled with default values based on Table 19-1 in 40 CFR Part 60, Appendix A. A default standard temperature of 68°F was used. This standard temperature was selected because EPA sampling methods rely on this value.

As discussed earlier, some pollutants were not detected in one or more of the sampling runs conducted during a test. In these cases, the detection limit was used in the emission calculations. Reports generated in the emissions database use a ?<? sign in front of the sampling run concentration, as well as the average concentration calculated for the three runs, to indicate when a pollutant was not detected in one or more of the runs. When a pollutant was not detected in all three runs, a ?<<? sign is shown in front of the average concentration presented in the database reports. The DL value was used in calculating the average concentration when a pollutant was not detected in one or more of the runs.

<u>Sample Of Modules Used In The Database</u>

The modules shown here are the modules for the calculation of emission factors in pounds per million Btu (Module Convert) and the module that handles the criteria for the use of detection limits (Module NonDetect).

1. <u>Module for the calculation of emission factors in pounds per million Btu</u>

1.1 Declaring the function that will perform the calculations and return the result to the query. The parameters r, s, t, u, v, w, z refer to concentration units (r), fuel factor (s), molecular weight (t), standard temperature (u), % oxygen (v), concentration (w), and a parameter (z, set to three in the database) used to limit the number of significant digits (utilizing another module) in the result.

```
Function lbMMBtu (r, s, t, u, v, w, x, y, z)
```

1.2 Estimating the emission factor to return to the query that is calling this module. First the module identifies the units (r=ppb), then it makes sure that there are values in all necessary fields and finally performs the calculation. SigDig_ is calling another module that will perform the reduction of the result to a given number (z) of significant digits. Val calls for the numerical value of the field being processed.

```
If ((r = "ppb") And Not (s = "NR" Or t = "NR" Or v = "NR" Or w = "NR")) Then
lbMMBtu = CStr(SigDig_((Val(s) * Val(t) * (.00000000137 / (Val(u) + 460)) *
(20.9 / (20.9 - Val(v))) * Val(w)), z))

ElseIf ((r = "ug/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * .000000002204 *
(20.9 / (20.9 - Val(v)))), z))
```

*ElseIf ((r = "ug/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .000000002204 * (20.9 / (20.9 - Val(v)))), z))*

*ElseIf ((r = "gr/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * (20.9 / (20.9 - Val(v))) / 7000), z))*

*ElseIf ((r = "ugr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) * 0.000001 / 7000), z))*

*ElseIf ((r = "gr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) / 7000), z))*

1.3 In any other case (units not recognized or necessary parameters were not reported) the function is returned with the value ?NR?

Else lbMMBtu = "NR" End If End Function

2. Module Handling the use of non-detected values

2.1 Declaring the function that will return the values to the query. The parameters x and y refer respectively to concentration and detection limit.

Function Correction (x, y)

2.2 Identifying the concentration. If it is not reported, return the value ?NR;? if it is not detected, take the value of the detection limit as the value for the concentration to be returned. Otherwise leave the value as it is.

If (x = "NR") Then Correction = "NR" ElseIf

If (x = "ND") Then Correction = y Else

Correction = x End If

End Function

Appendix C

QA\QC Review Criteria for Emissions Tests

Appendix C -- QA\QC Review Criteria for Emissions Tests

HAPS and Criteria Pollutant Source Test Checklist	Source Test Report #____ Date__________	Source Test Report #____ Date__________
BASIC TURBINE INFORMATION		
Manufacturer	_______________	_______________
Model #	_______________	_______________
Rating (BHP or MW)	_______________	_______________
Operating Cycle (Simple, Regenerative, etc.)	_______________	_______________
FUEL DESCRIPTION		
Fuel Name(s)	_______________	_______________
Fuel Analysis Summary	_______________	_______________
Flowrate (or BTU/H, if available)	_______________	_______________
OPERATING CONDITIONS		
Load (during test)	_______________	_______________
Water or Steam Injection and/or Ammonia Mass Flowrate	_______________	_______________
Firing Temperature or Turbine Inlet Temperature	_______________	_______________
AMBIENT CONDITIONS		
Temperature	_______________	_______________
Relative Humidity	_______________	_______________
Barometric Pressure	_______________	_______________
Altitude	_______________	_______________
EXHAUST INFORMATION		
Temperature	_______________	_______________
Flowrate (F-Factor or Measured)	_______________	_______________
EMISSIONS TEST		
*Criteria Pollutants	_______________	_______________
HAPS	_______________	_______________
Oxygen or CO_2	_______________	_______________
Moisture	_______________	_______________
Averaging Time	_______________	_______________
METHODS USED		
CARB	_______________	_______________
EPA	_______________	_______________
Other _____________________	_______________	_______________
QUALITY CONTROL DOCUMENTATION		
Calibration of Instruments	_______________	_______________
Specialty Gases	_______________	_______________
CEMs	_______________	_______________
Dry Gas Meters	_______________	_______________
MISCELLANEOUS		
Limits of Detection Reporting	_______________	_______________
Supplemental Firing Details	_______________	_______________

Appendix D

Development of Emission Factors (lb/MMBtu) for Natural Gas Fired Turbines

Appendix D

Development of Emission Factors (lb/MMBtu) for Natural Gas Fired Turbines

The emission factors (lb/MMBtu) presented in Table 1 were calculated for natural gas-fired turbines from 23 source test reports in the emissions database. Emission factors from test reports that did not meet acceptance criteria were not used in the calculations (4.1.2x, 8x, 10x, 29.1, 29.2, and 29.3). In addition, only test reports where the testing was conducted at high loads (greater than 80%) were included in the analysis. Test reports in which the load was not specified in the test report or could not be estimated from fuel use data were excluded.

The following test reports were used for the emission factor calculations: 2, 3.1, 4.2, 6.2, 7, 9, 11, 12.1, 13.1, 15.1, 17, 18, 22, 26, 27, 28, 313.1.1x, 313.2.1x, 314.1x, 315.1x, 316.1.1x, 316.2.1x, and 317.1x. Listed below are the source test reports that were excluded from the emission factor calculation with the reason for exclusion.

Test Report ID#	Reason for Exclusion
4.1.2x	Formaldehyde data point appears to be an outlier. Retest of the
8x	Report deemed inadequate by state and federal regulators
10x	Missing load and fuel usage data.
29.1, 29.2, 29.3	Only summary data provided; no raw data sheets, laboratory
16, 21, 313.1.2x,	Testing occurred only at operating loads less than 80%**.**
23, 25	Load information not available.

Test data for individual HAPs that were not detected in any of the sampling runs for a source test (i.e., where the concentration was ND in all three runs) were excluded from the emission factor calculation for that HAP. This exclusion was made on a pollutant basis such that data for a subset of the HAPs analyzed for in a particular source test may have been used.

Appendix E

Cost Spreadsheets

Appendix E -- Cost Spreadsheets

INPUTS AND CALCULATIONS

Model Turbine Number	1	
Turbine Exhaust Flow (lb/sec)	658	
Turbine Rating (MW)	85.4	
Turbine Rating (hp)	114523.1	
Heat Input, MMBtu/hr, including efficiency	832.5656	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	1595574	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1116874	EPA formula based on Vendor Quotes
Ductwork (no quantitative estimates available)		

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	1595574	1595574
Instrumentation**	0.1 EC	159557.4	159557.4
Sales Tax	0.03 EC	47867.23	47867.23
Freight	0.05 EC	79778.72	79778.72
Total Purchased Equipment Cost, PEC	1.18 EC	1882778	1882778
Direct Installation Costs			
Foundations & supports	0.08 PEC	150622.2	150622.2
Handling & erection	0.14 PEC	263588.9	263588.9
Electrical	0.04 PEC	75311.11	75311.11
Piping	0.02 PEC	37655.56	37655.56
Insulation for ductwork	0.01 PEC	18827.78	18827.78
Painting	0.01 PEC	18827.78	18827.78
Direct Installation Cost	0.3 PEC	564833.3	564833.3
Site preparation	As required, SP	0	0
Buildings	As required, Bldg	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	2447611	2447611

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	188277.8	188277.8
Construction and Field Expenses	0.05 PEC	94138.89	94138.89
Contractor Fees	0.1 PEC	188277.8	188277.8
Start-up	0.02 PEC	37655.56	37655.56
Performance test	0.01 PEC	18827.78	18827.78
Total Indirect Costs, IC	0.28 PEC	527177.8	527177.8
Contingencies	0.1 DC+IC	297478.9	297478.9
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	3272268	3272268
Direct Annual Costs (DAC)			
Fuel Penalty	1	17320	17320
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		5000	5000
Performance test not speciated HAPs			
Cat. Costs		17370.28	7806.717
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		425586.9	234315.6
Catalyst only cost * CRF cat			

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor		18250	18250
Operator - 2 hours per day			
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	2737.5	2737.5
Maintenance		188277.8	188277.8
Labor & Materials - .10 PEC	0.1 PEC		
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		674542.4	473707.6
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	125559.2	125559.2
Administrative	0.02 TCC	65445.36	65445.36
Property Taxes	0.01 TCC	32722.68	32722.68
Insurance	0.01 TCC	32722.68	32722.68
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		226840.5	226840.5
Total Indirect Annual Cost (IAC)		483290.3	483290.3
Total Annual Cost (TAC)		1157833	956997.9

INPUTS AND CALCULATIONS

Model Turbine Number	2	
Turbine Exhaust Flow (lb/sec)	986	
Turbine Rating (MW)	170	
Turbine Rating (hp)	227973.4	
Heat Input, MMBtu/hr, including efficiency	1657.332	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	2317985	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1622585	EPA formula based on Vendor Quotes
Ductwork (no quantitative estimates available)		

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	2317985	2317985
Instrumentation**	0.1 EC	2317898.5	2317898.5
Sales Tax	0.03 EC	69539.54	69539.54
Freight	0.05 EC	115899.2	115899.2
Total Purchased Equipment Cost, PEC	1.18 EC	2735222	2735222
Direct Installation Costs			
Foundations & supports	0.08 PEC	218817.8	218817.8
Handling & erection	0.14 PEC	382931.1	382931.1
Electrical	0.04 PEC	109408.9	109408.9
Piping	0.02 PEC	54704.44	54704.44
Insulation for ductwork	0.01 PEC	27352.22	27352.22
Painting	0.01 PEC	27352.22	27352.22
Direct Installation Cost	0.3 PEC	820566.6	820566.6
Site preparation	As required, SP	0	0
Buildings	As required, Bldg	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	3555789	3555789

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	273522.2	273522.2
Construction and Field Expenses	0.05 PEC	136761.1	136761.1
Contractor Fees	0.1 PEC	273522.2	273522.2
Start-up	0.02 PEC	54704.44	54704.44
Performance test	0.01 PEC	27352.22	27352.22
Total Indirect Costs, IC	0.28 PEC	765862.2	765862.2
Contingencies	0.1 DC+IC	432165.1	432165.1
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	4753816	4753816
Direct Annual Costs (DAC)			
Fuel Penalty	1	34470	34470
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		5000	5000
Performance test not speciated HAPs			
Cat. Costs		25235.39	11341.53
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1],			
i=interest rate, n=catalyst lifetime			
Catalyst replacement		618288.6	340411.5
Catalyst only cost * CRF cat			

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor			
Operator - 2 hours per day		18250	18250
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	2737.5	2737.5
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	273522.2	273522.2
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		977503.7	685732.7
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	176705.8	176705.8
Administrative	0.02 TCC	95076.32	95076.32
Property Taxes	0.01 TCC	47538.16	47538.16
Insurance	0.01 TCC	47538.16	47538.16
Capital Recovery		329540.3	329540.3
for catalyst: CRF equip (TCC - 1.08 (Cat only))			
Total Indirect Annual Cost (IAC)		696398.7	696398.7
Total Annual Cost (TAC)		1673902	1382131

INPUTS AND CALCULATIONS

Model Turbine Number	7	
Turbine Exhaust Flow (lb/sec)	318	
Turbine Rating (MW)	39.6	
Turbine Rating (hp)	53104.39	
Heat Input, MMBtu/hr, including efficiency	386.0609	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	84662.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	592662.4	EPA formula based on Vendor Quotes
Ductwork	(no quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	846662.4	846662.4
Instrumentation**	0.1 EC	84666.24	84666.24
Sales Tax	0.03 EC	25399.87	25399.87
Freight	0.05 EC	42333.12	42333.12
Total Purchased Equipment Cost, PEC	1.18 EC	999061.6	999061.6
Direct Installation Costs			
Foundations & supports	0.08 PEC	79924.93	79924.93
Handling & erection	0.14 PEC	139868.6	139868.6
Electrical	0.04 PEC	39962.47	39962.47
Piping	0.02 PEC	19981.23	19981.23
Insulation for ductwork	0.01 PEC	9990.616	9990.616
Painting	0.01 PEC	9990.616	9990.616
Direct Installation Cost	0.3 PEC	299718.5	299718.5
Site preparation	As required, SP	0	0
Buildings	As required, Bldg	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	1298780	1298780

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	99906.16	99906.16
Construction and Field Expenses	0.05 PEC	49953.08	49953.08
Contractor Fees	0.1 PEC	99906.16	99906.16
Start-up	0.02 PEC	19981.23	19981.23
Performance test	0.01 PEC	9990.616	9990.616
Total Indirect Costs, IC	0.28 PEC	279737.3	279737.3
Contingencies	0.1 DC+IC	157851.7	157851.7
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	1736369	1736369
Direct Annual Costs (DAC)			
Fuel Penalty	1	8030	8030
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		5000	5000
Performance test not speciated HAPs			
Cat. Costs		9217.431	4142.586
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		225835	124338.1
Catalyst only cost * CRF cat			

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor		18250	18250
Operator - 2 hours per day			
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	2737.5	2737.5
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	99906.16	99906.16
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		368976.1	262404.3
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	72536.2	72536.2
Administrative	0.02 TCC	34727.38	34727.38
Property Taxes	0.01 TCC	17363.69	17363.69
Insurance	0.01 TCC	17363.69	17363.69
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		120367.2	120367.2
Total Indirect Annual Cost (IAC)		262358.1	262358.1
Total Annual Cost (TAC)		631334.2	524762.5

INPUTS AND CALCULATIONS

Model Turbine Number	9	
Turbine Exhaust Flow (lb/sec)	178	
Turbine Rating (MW)	27	
Turbine Rating (hp)	36207.54	
Heat Input, MMBtu/hr, including efficiency	263.2233	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	538310.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	376810.4	EPA formula based on Vendor Quotes
Ductwork (no quantitative estimates available)		

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	538310.4	538310.4
Instrumentation**	0.1 EC	53831.04	53831.04
Sales Tax	0.03 EC	16149.31	16149.31
Freight	0.05 EC	26915.52	26915.52
Total Purchased Equipment Cost, PEC	1.18 EC	635206.3	635206.3
Direct Installation Costs			
Foundations & supports	0.08 PEC	50816.5	50816.5
Handling & erection	0.14 PEC	88928.88	88928.88
Electrical	0.04 PEC	25408.25	25408.25
Piping	0.02 PEC	12704.13	12704.13
Insulation for ductwork	0.01 PEC	6352.063	6352.063
Painting	0.01 PEC	6352.063	6352.063
Direct Installation Cost	0.3 PEC	190561.9	190561.9
Site preparation	As required, SP	0	0
Buildings	As required, Bldg	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	825768.2	825768.2

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	63520.63	63520.63
Construction and Field Expenses	0.05 PEC	31760.31	31760.31
Contractor Fees	0.1 PEC	63520.63	63520.63
Start-up	0.02 PEC	12704.13	12704.13
Performance test	0.01 PEC	6352.063	6352.063
Total Indirect Costs, IC	0.28 PEC	177857.8	177857.8
Contingencies	0.1 DC+IC	100362.6	100362.6
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	1103989	1103989
Direct Annual Costs (DAC)			
Fuel Penalty	1	5470	5470
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		5000	5000
Performance test not speciated HAPs			
Cat. Costs		5860.375	2633.826
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		143584.2	79053.24
Catalyst only cost * CRF cat			

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor			
Operator - 2 hours per day		18250	18250
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	2737.5	2737.5
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	63520.63	63520.63
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		244422.7	176665.2
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	50704.88	50704.88
Administrative	0.02 TCC	22079.77	22079.77
Property Taxes	0.01 TCC	11039.89	11039.89
Insurance	0.01 TCC	11039.89	11039.89
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		76530.51	76530.51
Total Indirect Annual Cost (IAC)		171394.9	171394.9
Total Annual Cost (TAC)		415817.7	348060.1

INPUTS AND CALCULATIONS

Model Turbine Number	15	
Turbine Exhaust Flow (lb/sec)	83.6	
Turbine Rating (MW)	9	
Turbine Rating (hp)	12069.18	
Heat Input, MMBtu/hr, including efficiency	87.74111	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	330364.5	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	231264.5	EPA formula based on Vendor Quotes
Ductwork	(no quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
Instrumentation**	0.1 EC	$23,658	$23,658
Sales Tax	0.03 EC	$7,098	$7,098
Freight	0.05 EC	$11,829	$11,829
Total Purchased Equipment Cost, PEC	1.18 EC	$279,169	$279,169
Direct Installation Costs			
Foundations & supports	0.08 PEC	$22,334	$22,334
Handling & erection	0.14 PEC	$39,084	$39,084
Electrical	0.04 PEC	$11,167	$11,167
Piping	0.02 PEC	$5,583	$5,583
Insulation for ductwork	0.01 PEC	$2,792	$2,792
Painting	0.01 PEC	$2,792	$2,792
Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation	As required, SP	$0	$0
Buildings	As required, Bldg	$0	$0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	$362,920	$362,920

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	$27,917	$27,917
Construction and Field Expenses	0.05 PEC	$13,958	$13,958
Contractor Fees	0.1 PEC	$27,917	$27,917
Start-up	0.02 PEC	$5,583	$5,583
Performance test	0.01 PEC	$2,792	$2,792
Total Indirect Costs, IC	0.28 PEC	$78,167	$78,167
Contingencies	0.1 DC+IC	$44,109	$44,109
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	$485,196	$485,196
Direct Annual Costs (DAC)			
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	330364.5	330364.5
Instrumentation**	0.1 EC	33036.45	33036.45
Sales Tax	0.03 EC	9910.934	9910.934
Freight	0.05 EC	16518.22	16518.22
Total Purchased Equipment Cost, PEC	1.18 EC	389830.1	389830.1
Direct Installation Costs			
Foundations & supports	0.08 PEC	31186.41	31186.41
Handling & erection	0.14 PEC	54576.21	54576.21
Electrical	0.04 PEC	15593.2	15593.2

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Piping	0.02 PEC	7796.602	7796.602
Insulation for ductwork	0.01 PEC	3898.301	3898.301
Painting	0.01 PEC	3898.301	3898.301
Direct Installation Cost	0.3 PEC	116949	116949
Site preparation	As required, SP	0	0
Buildings	As required, Bldg	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	506779.1	506779.1
Indirect Costs (Installation)			
Engineering	0.1 PEC	38983.01	38983.01
Construction and Field Expenses	0.05 PEC	19491.5	19491.5
Contractor Fees	0.1 PEC	38983.01	38983.01
Start-up	0.02 PEC	7796.602	7796.602
Performance test	0.01 PEC	3898.301	3898.301
Total Indirect Costs, IC	0.28 PEC	109152.4	109152.4
Contingencies	0.1 DC+IC	61593.15	61593.15
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	677524.7	677524.7
Fuel Penalty	1	1820	1820
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Performance Test		5000	5000
Performance test not speciated HAPs			
Cat. Costs		3596.76	1616.49
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		88123.72	48518.32
Catalyst only cost * CRF cat			
Operating Labor		18250	18250
Operator - 2 hours per day			
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	2737.5	2737.5
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	38983.01	38983.01
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		158511	116925.3

Indirect Annual Cost (IAC)

		3-Year Costs	6-Year Costs
Overhead	0.6 O&M costs	35982.31	35982.31
Administrative	0.02 TCC	13550.49	13550.49
Property Taxes	0.01 TCC	6775.247	6775.247
Insurance	0.01 TCC	6775.247	6775.247
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		46965.64	46965.64
Total Indirect Annual Cost (IAC)		110048.9	110048.9
Total Annual Cost (TAC)		268559.9	226974.3

INPUTS AND CALCULATIONS

Model Turbine Number	13	
Turbine Exhaust Flow (lb/sec)	41	
Turbine Rating (MW)	3.5	
Turbine Rating (hp)	4,694	
Heat Input, MMBtu/hr, including efficiency	34	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.1098	
Capital Recovery Factor, 3-yr Catalyst Life	0.3811	
Capital Recovery Factor, 6-yr Catalyst Life	0.2098	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	$236,584	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$165,584	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (no quantitative estimates available)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
Instrumentation**	0.1 EC	$23,658	$23,658
Sales Tax	0.03 EC	$7,098	$7,098
Freight	0.05 EC	$11,829	$11,829
Total Purchased Equipment Cost, PEC	1.18 EC	$279,169	$279,169
Direct Installation Costs			
Foundations & supports	0.08 PEC	$22,334	$22,334
Handling & erection	0.14 PEC	$39,084	$39,084
Electrical	0.04 PEC	$11,167	$11,167
Piping	0.02 PEC	$5,583	$5,583
Insulation for ductwork	0.01 PEC	$2,792	$2,792
Painting	0.01 PEC	$2,792	$2,792
Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation	As required, SP	$0	$0
Buildings	As required, Bldg	$0	$0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	$362,920	$362,920

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	$27,917	$27,917
Construction and Field Expenses	0.05 PEC	$13,958	$13,958
Contractor Fees	0.1 PEC	$27,917	$27,917
Start-up	0.02 PEC	$5,583	$5,583
Performance test	0.01 PEC	$2,792	$2,792
Total Indirect Costs, IC	0.28 PEC	$78,167	$78,167
Contingencies	0.1 DC+IC	$44,109	$44,109
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	$485,196	$485,196
Direct Annual Costs (DAC)			
Fuel Penalty	1.0	$710	$710
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		$5,000	$5,000
Performance test not speciated HAPs			
Cat. Costs		$2,575	$1,157
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		$63,096	$34,739
Catalyst only cost * CRF cat			

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor		$18,250	$18,250
Operator - 2 hours per day			
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	$2,738	$2,738
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	$27,917	$27,917
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		$120,286	$90,511
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	$29,343	$29,343
Administrative	0.02 TCC	$9,704	$9,704
Property Taxes	0.01 TCC	$4,852	$4,852
Insurance	0.01 TCC	$4,852	$4,852
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		$33,637	$33,637
Total Indirect Annual Cost (IAC)		$82,388	$82,388
Total Annual Cost (TAC)		$202,673	$172,898

INPUTS AND CALCULATIONS

Model Turbine Number	17	
Turbine Exhaust Flow (lb/sec)	14.2	
Turbine Rating (MW)	1.13	
Turbine Rating (hp)	1,515	
Heat Input, MMBtu/hr, including efficiency	11	(Rating in MW/.29307 MW/MMBTU/hr)/Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.1098	
Capital Recovery Factor, 3-yr Catalyst Life	0.3811	
Capital Recovery Factor, 6-yr Catalyst Life	0.2098	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation VAPPCI Escalator	50	for emissions reduction calculation
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (oF)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	$177,564	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$124,264	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (no quantitative estimates available)

Appendix E -- Cost Spreadsheets (Continued)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	$177,564	$177,564
Instrumentation**	0.1 EC	$17,756	$17,756
Sales Tax	0.03 EC	$5,327	$5,327
Freight	0.05 EC	$8,878	$8,878
Total Purchased Equipment Cost, PEC	1.18 EC	$209,525	$209,525
Direct Installation Costs			
Foundations & supports	0.08 PEC	$16,762	$16,762
Handling & erection	0.14 PEC	$29,334	$29,334
Electrical	0.04 PEC	$8,381	$8,381
Piping	0.02 PEC	$4,191	$4,191
Insulation for ductwork	0.01 PEC	$2,095	$2,095
Painting	0.01 PEC	$2,095	$2,095
Direct Installation Cost	0.3 PEC	$62,858	$62,858
Site preparation	As required, SP	$0	$0
Buildings	As required, Bldg	$0	$0
Total Direct Cost, DC	1.30 PEC + SP + Bldg	$272,383	$272,383

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Indirect Costs (Installation)			
Engineering	0.1 PEC	$20,953	$20,953
Construction and Field Expenses	0.05 PEC	$10,476	$10,476
Contractor Fees	0.1 PEC	$20,953	$20,953
Start-up	0.02 PEC	$4,191	$4,191
Performance test	0.01 PEC	$2,095	$2,095
Total Indirect Costs, IC	0.28 PEC	$58,667	$58,667
Contingencies	0.1 DC+IC	$33,105	$33,105
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg + 0.1 (DC + IC)	$364,154	$364,154
Direct Annual Costs (DAC)			
Fuel Penalty		$230	$230
Fuel Penalty due to Pressure Drop, Assume 1" backpressure			
Performance Test		$5,000	$5,000
Performance test not speciated HAPs			
Cat. Costs		$1,933	$869
Freight to return catalyst for disposal			
Freight=.05*Catalyst only cost *[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			
Catalyst replacement		$47,351	$26,070
Catalyst only cost * CRF cat			

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Operating Labor		$18,250	$18,250
Operator - 2 hours per day			
Per Engine ACT-NSCR			
Supervisor - .15 *OL	0.15 OL	$2,738	$2,738
Maintenance			
Labor & Materials - .10 PEC	0.1 PEC	$20,953	$20,953
Per Engine ACT-NSCR			
Total Direct Annual Cost (DAC)		$96,453	$74,109
Indirect Annual Cost (IAC)			
Overhead	0.6 O&M costs	$25,164	$25,164
Administrative	0.02 TCC	$7,283	$7,283
Property Taxes	0.01 TCC	$3,642	$3,642
Insurance	0.01 TCC	$3,642	$3,642
Capital Recovery - for catalyst: CRF equip (TCC - 1.08 (Cat only))		$25,247	$25,247
Total Indirect Annual Cost (IAC)		$64,977	$64,977
Total Annual Cost (TAC)		$161,431	$139,086

Appendix F

Description of SCONOx^{TM} System

Appendix F -- Description of SCONOx™ System

The SCONOx™ catalytic absorption system was described in a paper presented at the Power-Gen International '97 conference as follows:

> The SCONOx™ system uses a single catalyst for both CO & NOx control. It oxidizes CO to CO_2 and NO to NO_2, and the NO_2 is then absorbed onto the surface of the catalyst. Just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be periodically regenerated. This is accomplished by passing a dilute hydrogen gas across the surface of the catalyst in the absence of oxygen. Nitrogen oxides are broken down into nitrogen and water, and this is exhausted up the stack instead of NOx.

Source: "The SCONOx™ Catalytic Absorption system for Natural Gas Fired Power Plants: The Path to Ultra-Low Emissions," Robert J. MacDonald, P.E., and Lawrence Debbage, presented to Power-Gen International '97, December 9-11, 1997.

Appendix G

Cost-Effectiveness for Individual HAPs

Appendix G -- Cost-Effectiveness for Individual HAPs

Model 1 -- 85.4 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$85,213	$670,472	$70,432	$554,173	$112,692	$886,677
Toluene	$629,008	$3,366,524	$519,902	$2,782,575	$831,843	$4,452,120
Acetaldehyde	$1,365,847	$5,241,737	$1,128,930	$4,332,518	$1,806,289	$6,932,029
Xylenes	$3,983,720	$10,414,955	$3,292,714	$8,608,402	$5,268,342	$13,773,443
Ethylbenzene	$11,659,669	$11,659,669	$9,637,211	$9,637,211	$15,419,538	$15,419,538
Benzene	$12,226,251	$46,412,275	$10,105,515	$38,361,714	$16,168,825	$61,378,743
PAHs	$65,306,889	$214,370,595	$53,978,915	$177,186,393	$86,366,264	$283,498,228
Acrolein	$78,626,057	$87,075,852	$64,987,772	$71,971,886	$103,980,436	$115,155,018
Naphthalene	$144,424,903	$327,429,060	$119,373,310	$270,634,011	$190,997,296	$433,014,417
Total HAPs	$68,914	$454,166	$56,961	$375,388	$91,137	$600,620

Model 2 -- 170 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$61,887	$486,938	$51,100	$402,062	$81,760	$643,299
Toluene	$456,825	$2,444,978	$377,198	$2,018,804	$603,516	$3,230,087
Acetaldehyde	$991,963	$3,806,874	$819,058	$3,143,314	$1,310,492	$5,029,302
Xylenes	$2,893,224	$7,563,985	$2,388,918	$6,245,538	$3,822,269	$9,992,861
Ethylbenzene	$8,467,973	$8,467,973	$6,991,956	$6,991,956	$11,187,129	$11,187,129
Benzene	$8,879,461	$33,707,467	$7,331,718	$27,832,058	$11,730,750	$44,531,292
PAHs	$47,429,906	$155,689,197	$39,162,595	$128,551,656	$62,660,151	$205,682,649
Acrolein	$57,103,110	$63,239,874	$47,149,703	$52,216,793	$75,439,524	$83,546,868
Naphthalene	$104,890,305	$237,799,252	$86,607,309	$196,349,447	$138,571,694	$314,159,115
Total HAPs	$50,050	$329,844	$41,326	$272,350	$66,122	$435,760

Model 7 -- 39.6 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$100,204	$788,418	$83,289	$655,330	$133,262	$1,048,528
Toluene	$739,661	$3,958,748	$614,803	$3,290,496	$983,685	$5,264,793
Acetaldehyde	$1,606,121	$6,163,841	$1,335,001	$5,123,360	$2,136,002	$8,197,375
Xylenes	$4,684,519	$12,247,109	$3,893,753	$10,179,747	$6,230,005	$16,287,596
Ethylbenzene	$13,710,787	$13,710,787	$11,396,351	$11,396,351	$18,234,162	$18,234,162
Benzene	$14,377,040	$54,576,921	$11,950,138	$45,364,117	$19,120,221	$72,582,586
PAHs	$76,795,394	$252,081,741	$63,832,022	$209,529,327	$102,131,235	$335,246,924
Acrolein	$92,457,612	$102,393,858	$76,850,395	$85,109,363	$122,960,632	$136,174,980
Naphthalene	$169,831,505	$385,028,960	$141,163,263	$320,034,521	$225,861,221	$512,055,233
Total HAPs	$81,038	$534,061	$67,358	$443,910	$107,773	$710,255

Model 9 -- 27 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$96,796	$761,608	$81,023	$637,504	$129,637	$1,020,007
Toluene	$714,509	$3,824,133	$598,080	$3,200,990	$956,927	$5,121,583
Acetaldehyde	$1,551,505	$5,954,241	$1,298,687	$4,983,997	$2,077,900	$7,974,395
Xylenes	$4,525,223	$11,830,650	$3,787,838	$9,902,844	$6,060,540	$15,844,550
Ethylbenzene	$13,244,556	$13,244,556	$11,086,354	$11,086,354	$17,738,167	$17,738,167
Benzene	$13,888,154	$52,721,050	$11,625,077	$44,130,148	$18,600,124	$70,608,237
PAHs	$74,183,991	$243,509,783	$62,095,700	$203,829,832	$99,353,120	$326,127,732
Acrolein	$89,313,621	$98,911,988	$74,759,955	$82,794,267	$119,615,928	$132,470,827
Naphthalene	$164,056,440	$371,936,175	$137,323,422	$311,329,127	$219,717,475	$498,126,604
Total HAPs	$78,282	$515,901	$65,526	$431,835	$104,841	$690,935

Model 13 -- 3.5 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$363,955	$2,863,658	$310,486	$2,442,953	$496,777	$3,908,725
Toluene	$2,686,563	$14,378,788	$2,291,876	$12,266,378	$3,667,001	$19,626,205
Acetaldehyde	$5,833,680	$22,388,026	$4,976,645	$19,098,966	$7,962,632	$30,558,345
Xylenes	$17,014,900	$44,483,398	$14,515,214	$37,948,271	$23,224,342	$60,717,234
Ethylbenzene	$49,799,706	$49,799,706	$42,483,553	$42,483,553	$67,973,684	$67,973,684
Benzene	$52,219,641	$198,231,840	$44,547,971	$169,109,287	$71,276,753	$270,574,860
PAHs	$278,932,781	$915,599,980	$237,954,325	$781,087,739	$380,726,920	$1,249,740,383
Acrolein	$335,820,387	$371,910,374	$286,484,483	$317,272,433	$458,375,173	$507,635,893
Naphthalene	$616,854,367	$1,398,484,901	$526,231,317	$1,193,031,273	$841,970,107	$1,908,850,037
Total HAPs	$294,341	$1,939,794	$251,099	$1,654,815	$401,758	$2,647,705

Model 15 -- 9 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$187,550	$1,475,677	$158,509	$1,247,173	$253,614	$1,995,477
Toluene	$1,384,418	$7,409,561	$1,170,045	$6,262,213	$1,872,072	$10,019,541
Acetaldehyde	$3,006,165	$11,536,816	$2,540,669	$9,750,376	$4,065,071	$15,600,602
Xylenes	$8,767,980	$22,922,824	$7,410,286	$19,373,296	$11,856,457	$30,997,274
Ethylbenzene	$25,662,381	$25,662,381	$21,688,641	$21,688,641	$34,701,826	$34,701,826
Benzene	$26,909,402	$102,151,226	$22,742,565	$86,333,426	$36,388,104	$138,133,482
PAHs	$143,737,381	$471,819,563	$121,480,094	$398,759,771	$194,368,151	$638,015,633
Acrolein	$173,052,241	$191,649,841	$146,255,640	$161,973,459	$234,009,023	$259,157,534
Naphthalene	$317,872,394	$720,655,908	$268,650,843	$609,064,582	$429,841,348	$974,503,331
Total HAPs	$151,677	$999,599	$128,191	$844,814	$205,105	$1,351,702

Model 17 -- 1.13 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$897,899	$7,064,815	$773,614	$6,086,919	$1,237,782	$9,739,070
Toluene	$6,627,912	$35,473,330	$5,710,491	$30,563,190	$9,136,785	$48,901,104
Acetaldehyde	$14,392,037	$55,232,597	$12,399,923	$47,587,423	$19,839,877	$76,139,877
Xylenes	$41,976,774	$109,743,200	$36,166,442	$94,552,789	$57,866,307	$151,284,462
Ethylbenzene	$122,858,851	$122,858,851	$105,853,000	$105,853,000	$169,364,800	$169,364,800
Benzene	$128,828,974	$489,049,793	$110,996,752	$421,356,601	$177,594,803	$674,170,562
PAHs	$688,143,835	$2,258,839,853	$592,892,485	$1,946,176,230	$948,627,977	$3,113,881,969
Acrolein	$828,488,959	$917,525,113	$713,811,348	$790,523,314	$1,142,098,156	$1,264,837,302
Naphthalene	$1,521,816,578	$3,450,145,803	$1,311,170,089	$2,972,584,242	$2,097,872,142	$4,756,134,788
Total HAPs	$726,157	$4,785,587	$625,644	$4,123,176	$1,001,030	$6,597,082

ATTACHMENT VI

INTERPRETING AND USING EMISSIONS DATABASES CONTAINING NON-DETECTION VALUES

Industrial Combustion Coordinated Rulemaking
Federal Advisory Committee

September 16, 1998

Interpreting and Using Emissions Databases Containing Non-detection Values

With the existing EPA ICCR emission database and other databases, there is a need to obtain mean and/or median values and variability for data sets for various reasons. The most critical reason might be determining whether a toxic emission from a group of potential emissions sources warrants further consideration.

Any decision to control HAP emissions from combustion sources should be made on the basis of fuel composition, combustion science, and actual observations. No decisions leading to the imposition of control devices or emission limits on combustion processes should be made that are based on emission levels derived from default HAP concentrations calculated from method detection levels.

A "critical concentration level" should be identified below which HAP emissions are not significant for the purposes of data gathering as part of any future emissions testing.

These steps should be followed when making decisions that involve interpretation of databases with reported non-detection reports for some pollutants:

Step 1: In addition to emission concentration levels, consider fuel composition, scientific and engineering data to focus efforts towards HAP emissions that are potentially significant. Doing this is critical for non-detection and other issues because it is impractical and simply not necessary to solely rely on stack testing to rule out all 189 chemicals that appear on the EPA toxics substances list. Material balances using fuel composition and consumption rates along with published flame chemistry science are most useful in this regard. Most potential non-detection issues can best be circumvented by completion of Step 1.

Step 2: Associate detection limits with individual source tests that resulted in non-detection reports either by retrieving the detection limit from the database, or assigning conservative detection limits based on the descriptions of the measurement procedures. Retrieval is preferred, but assignments without uncertainties are not realistic.

Step 3: Assume that the actual concentrations could be as high as the detection limits to determine if the emissions have the potential to be important even with the highest potential concentration. If the answer is no, there is no need for the following steps.

Step 4: Create a data subset which contains only those source measurements that have the lowest detection limits, and repeat Step 3. If the answer becomes no, and if the subset is representative of the industry emissions sources, there is no need for the following steps.

Step 5: Define the detection level that is needed to resolve the issues relative to the emission of a specific HAP, this sets a "critical concentration level" below which emissions are not significant.

Step 6: The best course of action for filling data gaps is the collection of data using methodology with the appropriately low detection limits. A less desirable alternative is to use the ½ detection limit substitution method on an existing database.

The publications by Helsel[6], Coleman, *et. al*[7]., and Zorn *et. al*.[8] address the issues of dealing with databases that contain a mixture of detection and non-detection values, and give procedures for determining mean and median values. Procedures that are discussed and provided range from simple substitution to complex statistical methods. The publications show mean and median values can be generated with the highest certainty when:

1. The detection limits for each measurement is known with certainty, and when the detection limit and the definition of the detection limit are consistent.
2. The ratio of non-detection to detection values is less than 1, and when there are enough detectable values so the mean and median values are not dominated by statistical outliers.

Simple substitution methods using the ½ detection limits generally perform poorly as compared to the more complex statistical methodology when the above conditions were met. Substitution of zero for the detection limit was discouraged because it will result in a low bias, and substitution of the detection limit was discouraged because it will result in a high bias. Limitations in the existing database make the ½ detection limits substitution method the most applicable for working with existing databases. But testing with appropriate detection limits is the most reliable approach for filling data gaps.

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[1] Dennis R. Helsel, "Less than obvious: statistical treatment of data below the detection limit", Environ. Sci. Technol., 1990, Vol. 24, pp. 1766 - 1774.

[2] David Coleman, *et.al.*, "Regulation between detection limits, quantification limits, and significant digits" Chemometics and Intelligent Laboratory Systems, 1997, Vol. 37, pp 71-80.

[8] Michael E. Zorn, *et. al.*, "Weighted least-squares approach to calculating limits of detection and quantification by modeling variability as a function of concentration", Anal. Chem., 1997, Vol. 69, pp. 3069-3075.

ATTACHMENT VII

DEFINITION OF "RICH BURN ENGINE" FOR THE RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE) MACT STANDARD

Industrial Combustion Coordinated Rulemaking
Federal Advisory Committee

September 16, 1998

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I. INTRODUCTION

Stationary reciprocating internal combustion engines (RICE) operate with various air-to-fuel ratios and, in general, may be classified as either rich or lean of stoichiometry. Stoichiometry is a precise point that may be defined as the chemically correct air-to-fuel ratio that would be required for complete combustion. Rich of stoichiometry refers to fuel-rich combustion, i.e., operation at any air-to-fuel ratio less than stoichiometry. Lean of stoichiometry refers to fuel-lean combustion, i.e., operation at any air-to-fuel ratio numerically higher than stoichiometry. All compression-ignition engines run lean of stoichiometry. Spark-ignition engines may run either rich or lean of stoichiometry, depending on engine design and setpoints for fuel flow and intake air.

There should be a subcategory for Spark-Ignition, Natural Gas, 4-Stroke, Rich Burn engines (SI-NG-4SRB). However, the ICCR Coordinating Committee has no recommendation on the appropriate regulatory definition for the RICE MACT standard to best distinguish engines in that subcategory from engines that would be included in the Spark-Ignition, Natural Gas, 4-Stroke, Lean Burn (SI-NG-4SLB) subcategory. The Coordinating Committee is forwarding the information presented in this paper to EPA to consider in developing the regulatory definition of "rich burn engines" for the RICE MACT standard.

The need for a definition of rich burn in the context of the RICE MACT standard is discussed below, along with a list of possible definitions. Sections II through VII provide a record of the definitions considered, the instances where these definitions have been used previously, and the pros and cons of the use of the definitions for the RICE MACT standard.

The final section of this paper presents the conclusions of the Coordinating Committee regarding the definition of "rich burn engine".

A. Need for a Definition of "Rich Burn Engine" for the RICE MACT Standard

As indicated above, the need for a regulatory definition of "rich burn engine" arose out of the need to distinguish those engines that would be included in the SI-NG-4SRB subcategory from those engines that would be included in the SI-NG-4SLB subcategory for the RICE MACT standard.

For existing engines, ten subcategories have been identified:

- Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines
- Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines
- Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines
- Spark-Ignition, Digester Gas and Landfill Gas Engines

- Spark-Ignition, Propane, Liquid Petroleum Gas (LPG), and Process Gas Engines
- Spark-Ignition, Gasoline Engines
- Compression-Ignition, Liquid Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)
- Compression-Ignition, Dual Fuel Engines
- Emergency Power Units
- Small Engines (200 brake horsepower or less)

Engines included in the Emergency Power Units subcategory were identified by the engine's use on an emergency basis. Engines in the Small Engines subcategory were identified by size (engines 200 brake horsepower or less). For engines that were not considered emergency power units or small engines, engines may be subcategorized by whether the engines were spark-ignited or compression-ignited and by fuel type. For natural gas, engines may also be subcategorized based on whether the engines were 2-stroke and 4-stroke engines and whether the engines were lean burn engines or rich burn engines.

The natural gas-fired engines may be subcategorized further than engines using fuels other than natural gas for the following reasons:

- To reflect the engineering differences between 2-stroke and 4-stroke, rich-burn and lean-burn engines, and

- To reflect the fact that there are two most prevalent control devices in the existing population of engines that involve oxidation (1) a 3-way catalyst, known as non-selective catalytic reduction (NSCR), and (2) oxidation catalysts. NSCR is mostly used on "rich burn engines", and oxidation catalysts are mostly used on "lean burn" engines for criteria pollutant control.

It is necessary to further subcategorize natural gas-fired engines. For the MACT floor analysis, 4-stroke natural gas-fired engines included in the ICCR Population Database were designated as SI-NG-4SRB or SI-NG-4SLB based on the manufacturer's designation of the engine model as a "rich burn engine" or a "lean burn engine." As a result of this analysis, the MACT floor for SI-NG-4SRB engines should be based on NSCR. For engines in all subcategories other than SI-NG-4SRB, no MACT floor could be identified and therefore there is no MACT floor for those subcategories.

Although the designation of an engine as "rich burn" by the manufacturer was used to analyze data in the ICCR Population Database to determine the MACT floor, the MACT Floor does not include a definition for the SI-NG-4SRB subcategory or for "rich burn engines." A common method used to distinguish between "rich burn" and "lean burn" engines is the percentage oxygen in the exhaust stream. Several regulatory agencies have adopted a value of 4 percent oxygen in the exhaust as the defining limit for "rich burn" engines.

A number of possible regulatory definitions of “rich burn engine” however have been identified for the purposes of the RICE MACT standard. Some believe that the regulatory definition of "rich burn engines" should be based on technical characteristics of the engine. Possible technical characteristics that have been discussed for the definition of "rich burn engines" include air-to-fuel ratio, lambda (air-to-fuel ratio divided by stoichiometric air-to-fuel ratio), exhaust oxygen content, and the manufacturer's designation of the engine as "rich burn." Some also believe the SI-NG-4SRB subcategory should include only those engines that can use NSCR as a 3-way catalyst for the simultaneous reduction of NOx, CO, and HC. Others believed that "rich burn engines" should include engines beyond those that may use NSCR as a 3-way catalyst, so long as all "rich burn engines" could meet the MACT requirements for the SI-NG-4SRB subcategory through the use of any device, such as an oxidation catalyst or an NSCR used solely for oxidation.

The possible definitions discussed to date are listed in the following section.

B. Possible Definitions of Rich Burn

The following definitions of “rich burn engine” have been identified:

- "Rich burn means engines that are designated as ‘rich-burn’ by the manufacturer based on the design of the engine model when manufactured.”

- "Rich burn means engines that can use non-selective catalytic reduction control technology.”

- "Rich burn means an engine with an air-to-fuel ratio (A/F) operating range that is near to stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."

- "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the manufacturer’s original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”

- "Rich burn engine means a two stroke or four-stroke spark-ignited engine where the operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”

- "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 4 percent or less measured on a dry basis."

- "Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 1 percent or less measured on a dry basis."

Discussion of these definitions is provided in Sections II through VII.

II. ENGINES DESIGNATED RICH BURN BY THE MANUFACTURER

"Rich burn means engines that are designated as 'rich-burn' by the manufacturer based on the design of the engine model when manufactured."

Pros:

- Definition is consistent with the methodology used to designate engines as "rich burn" in the ICCR Population Database. The engines designated as "rich burn" were used to determine the MACT floor for the SI-NG-4SRB subcategory.

- Since the definition relies on the manufacturer's original designation of the engine as a rich burn, owners or operators do not have the opportunity to adjust the engine to lean-burn status to avoid rich-burn regulatory requirements.

  [Note: For NO_X, regulators were very concerned about this possibility since there were higher NO_X emission limitations for lean-burn engines, which relied on different control technologies to reduce NO_X. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

Cons:

- The definition of "rich burn engine" would be based solely on the manufacturer designation, and there is not a definite cutpoint for rich burn that has been used consistently for all engine manufacturers. However, since engines with air/fuel ratios of around 16:1 are designated "rich burn" by manufacturers and engines with air/fuel ratios no less than 24:1 are designated "lean-burn," this should not be a significant problem.

- The definition relies on the designation specified by the manufacturer at the time of manufacture. The definition does not accommodate the re-manufacture and re-construction of existing engines which may result in conversions of engines originally specified as "rich burn" to operate significantly lean of stoichiometric conditions. The modified engines may have engineering and operating characteristics more closely akin to lean burn engines than to rich burn engines.

- Many rich-burn engines operate slightly lean of stoichiometric conditions. For those engines, the exhaust oxygen concentration may be higher than the level required to use NSCR controls as intended for NO_X control. In order to use NSCR as intended for NO_X control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.
- In most cases, operators who install NSCR use an air-to-fuel ratio controller to maintain the proper air-to-fuel ratio and exhaust gas oxygen content required to use NSCR technology as intended for NO_X control. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads.

Instances Where the Definition Has Been Used Previously:

- NONE

III. ENGINES THAT CAN USE NON-SELECTIVE CATALYTIC REDUCTION

"Rich burn means engines that can use non-selective catalytic reduction control technology."

Pros:

- Limits "rich burn engines" to only those engines that can use NSCR. With this definition, NSCR would be achievable for all engines in the subcategory.

Cons:

- The definition of "rich burn engine" would be based solely on a control technology, not the engineering characteristics of the engine.

- "Can use NSCR" is not a precise, measurable characteristic. To be covered under this definition, an engine must be able to be operated with NSCR as intended for NO_X control. To avoid being covered under this definition, source owners and operators would need to demonstrate to permitting/enforcement personnel that the engine cannot be operated with NSCR. [Note: In the latter case, the engine would be covered under requirements for lean burn engines.]

Instances Where the Definition Has Been Used Previously:

- NONE

IV. ENGINES NEAR TO STOICHIOMETRIC OR FUEL-RICH OF STOICHIOMETRIC

"Rich burn means an engine with an air-to-fuel ratio (A/F) operating range that is near to stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."

Pros:

- Fuel-rich of stoichiometric is a precise, measurable point.

- Limits "rich burn engines" to only those engines that can be adjusted to operate with an exhaust oxygen concentration that is compatible with the use of NSCR as intended for NO_X control. With this definition, NSCR would function as intended for NO_X control on all "rich burn engines".

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines, which may result in higher exhaust oxygen content than the levels specified by the design of the engine manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of an existing engine, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

Cons:

- Near to stoichiometric is not a precise, measurable point. Under this definition, for engines operating fuel-lean of stoichiometric, it would be necessary for source owners and operators to demonstrate to permitting/enforcement personnel that the engine could not be operated with an exhaust oxygen concentration of 1 percent or less.

- Since near to stoichiometric is not a precise point, it is unclear whether engines operating slightly lean of stoichiometric are included. Engine manufacturers do include engines slightly lean of stoichiometric as "rich burn."

- To determine whether an engine is covered under this definition, it is necessary to know the stoichiometric air-to-fuel ratio for the fuel being used, along with the operating air-to-fuel ratio. To determine operating air-to-fuel ratio, engine operators need to measure at least the oxygen content of the exhaust.

- The definition relies on air-to-fuel ratio, which is difficult to precisely measure in the field.

Instances Where the Definition Has Been Used Previously:

- The EPA Alternative Control Techniques Document for Nitrogen Oxide Emissions from Stationary Reciprocating Internal Combustion Engines uses this definition:

  “A rich-burn engine is classified as one with an air-to-fuel ratio (A/F) operating range that is near stoichiometric or fuel-rich of stoichiometric and can be adjusted to operate with an exhaust oxygen concentration of 1 percent or less."

V. ENGINES WHERE THE AIR-TO-FUEL RATIO DIVIDED BY STOICHIOMETRIC AIR-TO-FUEL RATIO (LAMBDA) IS 1.1 OR LESS

"Rich burn engine means a two stroke or four-stroke spark-ignited engine where the manufacturer’s original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”

and

"Rich burn engine means a two stroke or four-stroke spark-ignited engine where the operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1.”

Pros:

- A lambda target, such as 1.1, is independent of fuel, whereas air-to-fuel ratio alone would be fuel dependent.

- Lambda 1.1 is a technically precise point, making compliance determinations definitive.

- If the definition relies on the manufacturer’s original recommended air-to-fuel ratio, owners or operators do not have the opportunity to adjust the engine to lean-burn status to avoid rich burn regulatory requirements.

- To determine operating air-to-fuel ratio, engine operators can measure the oxygen content of the exhaust.

Cons:

- Lambda is more difficult to measure/calculate than exhaust oxygen levels. Two air-to-fuel ratios are necessary to determine lambda: the stoichiometric air-to-fuel ratio and either the manufacturer's recommended air-to-fuel ratio or the operating air-to-fuel ratio. The manufacturer's recommended air-to-fuel ratio may be difficult to determine for older engines. Where fuel composition changes significantly, the stoichiometric air-to-fuel ratio may be difficult to determine, since it is dependent on fuel composition. The operating air-to-fuel ratio is difficult to precisely measure in the field.

- If the definition relies on the air-to-fuel ratio originally specified by the engine manufacturer, the definition does not accommodate the diverse operating conditions of existing engines and the re-manufacture and re-construction of existing engines which may result in different air-to-fuel ratios than those specified by the design of the engine manufacturer.

- If the definition relies on lambda calculated with the current operating air-to-fuel ratio (not the manufacturer's specifications), owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise lambda and thereby qualify the engine as a "lean burn engine." The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

  [Note: For NO_X, regulators were very concerned about this possibility since there were higher NO_X emission limitations for lean-burn engines, which relied on different control technologies to reduce NO_X. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- A lambda of 1.1 corresponds to approximately 2 percent oxygen in the exhaust. An exhaust concentration of 2 percent would not be compatible with the use of NSCR controls as intended for NO_X control. In order to use NSCR as intended for NO_X control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.

- NSCR may not be achievable for all engines in the rich burn subcategory if this definition were adopted. In order to use NSCR as intended for NO_X control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads. However, engines may be able to use other devices to comply with MACT.

Instances Where the Definition Has Been Used Previously:

- California's Ventura County and Sacramento Air Quality Management Districts, Rules 74.9 and 412, define rich burn engine as follows:

  "A two-stroke or four-stroke spark-ignited engine where the manufacturers original recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1."

VI. ENGINES WITH 4 PERCENT OR LESS EXCESS OXYGEN IN THE EXHAUST

"Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 4 percent or less measured on a dry basis."

Pros:

- Oxygen content of the exhaust is easy to measure on-site and determine whether an engine meets the criteria of 4 percent or less.

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines that may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition is used by some engine manufacturers.

- Since the exhaust oxygen limit is set fairly high, it would be difficult for engine owners and operators to adjust the air-to-fuel ratio sufficiently to raise the oxygen level in the exhaust and thereby qualify the engine as a "lean burn engine."

Cons:

- Definition is significantly to the lean side of stoichiometry.

- If the definition relies on exhaust concentration based on the current operating air-to-fuel ratio (not the manufacturer's specifications), owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise the oxygen content and thereby qualify the engine as a "lean burn engine." The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

  [Note: For NO_X, regulators were very concerned about this possibility since there were higher NO_X emission limitations for lean-burn engines, which relied on different control technologies to reduce NO_X. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- An exhaust concentration of 4 percent is not compatible with the use of NSCR as intended for NO_X control. In order to use NSCR as intended for NO_X control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, engines may be able to use other devices to comply with MACT.

- NSCR as intended for NO_X control would not be achievable for all engines in the rich burn subcategory if this definition were adopted. In order to use NSCR as intended for NO_X control, it would be necessary to adjust the engine to run at 1 percent oxygen or less. However, for some older models of engines, commercially available air-to-fuel ratio controllers cannot ensure that the engines will operate with exhaust concentrations of 1 percent oxygen or less, at all load conditions, including low-loads. However, engines may be able to use other devices to comply with MACT.

<u>Instances Where the Definition Has Been Used Previously:</u>

- EPA AP-42 Emission Factors for Reciprocating Internal Combustion Engines uses this definition.

- Texas environmental regulations, Chapter 106, Exemptions from Permitting, 106.512, defines "rich burn engine" as "a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0 percent by volume." [Note: The definition in Texas's Chapter 117, Control of Air Pollution from Nitrogen Oxides, defines "rich burn engine" as a spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5 percent by volume, as originally designed by the manufacturer."]

- California's Bay Area Air Quality Management District Rules and Regulations, BAAWMD Regulation 9-8-205 defines rich burn engine as follows:

  "Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of less than 4 percent, by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream."

- California's South Coast Air Quality Management District Rule 1110.1, includes the following definition:

  "A rich-burn engine is an Otto cycle engine that can be adjusted to run with an exhaust stream oxygen concentration of less than 4 percent by volume."

- California's Santa Barbara County APCD Rule 333 defines "rich burn engine" as an engine with 4 percent oxygen in the exhaust, but also limits engines already permitted as "rich burn engines" from changing their designation after the date of rule adoption:

  "Rich-burn engine means a spark-ignited, Otto cycle, or four-stroke naturally aspirated engine that is operated with an exhaust stream oxygen concentration of less than 4 percent by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream. Additionally, any engine which is designated as a rich-burn engine on a District Permit on the date of rule adoption shall be a rich-burn engine."

VII. ENGINES WITH 1 PERCENT OR LESS EXCESS OXYGEN IN THE EXHAUST

"Rich burn means a four-stroke, spark-ignited engine where the oxygen content in the exhaust stream before any dilution is 1 percent or less measured on a dry basis."

<u>Pros:</u>

- Oxygen content of the exhaust is easy to measure on-site and determine whether an engine meets the criteria of 1 percent or less.

- The definition is consistent with the use of NSCR as intended for NO_X control, which requires that oxygen be 1 percent or less. With this definition, the use of NSCR as intended for NO_X control would be achievable for all rich burn engines.

- Definition reflects the operating conditions of the engine, not simply the conditions specified by the manufacturer. Therefore, the definition accommodates diverse operating conditions of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

- Definition takes into account the possible re-manufacture or re-construction of existing engines, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

<u>Cons:</u>

- If the definition relies on exhaust oxygen content based on current operating air-to-fuel ratio (not the manufacturer's specifications), engine owners and operators would have the opportunity to adjust the air-to-fuel ratio to raise the oxygen level in the exhaust and thereby qualify the engine as a “lean burn engine.” The definition does not incorporate sufficient constraints to prohibit engine owners and operators from temporarily adjusting the engine to avoid rich burn regulatory requirements.

  [Note: For NO_X, regulators were very concerned about this possibility since there were higher NO_X emission limitations for lean-burn engines, which relied on different control technologies to reduce NO_X. For the RICE MACT standard, similar oxidation control technologies have been identified for both rich burn and lean burn engines. However, it is unclear whether the MACT standard for SI-NG-4SRB engines will be the same or nearly the same as the MACT standard for SI-NG-4SLB engines.]

- While this definition limits rich burn engines to those engines with 1 percent or less exhaust oxygen content, some engine manufacturers use a definition of 4 percent exhaust gas oxygen content.

- The definition limits "rich burn engines" to those engines that may use NSCR as intended for NO_X control. However, it is unclear whether this is important for the RICE MACT, because the RICE MACT may permit the use of alternate controls that are consistent with other definitions.

<u>Instances Where the Definition Has Been Used Previously:</u>

- Massachusetts regulations, Title 310, Chapter 7. Air Pollution Control, defines “rich burn engine” as “any stationary reciprocating internal combustion engine that is not a lean burn engine.” “Lean burn engine” is defined as “a stationary reciprocating internal combustion engine in which the amount of O2 in the engine exhaust gases is 1.0 percent or more.”

- Ohio environmental regulations (OAC 3745-14-01(B)(30), Effective 6/21/94) and Rhode Island (Subsection 27.1.23 of Air Pollution Control Regulation No. 27, Amended 1/16/96) use similar definitions:

> "Rich burn engine means an internal combustion engine where the amount of oxygen in the engine exhaust gases is less than one percent, by weight."

- New York environmental regulations, 6 NYCRR 227-2.2(b)(15), Filed 1/19/94, define "rich burn internal combustion engine" as "any stationary internal combustion engine that is not a lean burn engine as described in paragraph (8) of this subdivision." Paragraph 8 defines "lean burn internal combustion engine" as "any stationary internal combustion engine that is operated so that the amount of oxygen in the exhaust is 1.0 percent or more, by volume."

- North Carolina environmental regulations, Administrative Code 15A, Chapter 2d, Section 1401(15), Effective 4/1/95, define 1 percent as the break-point for rich burn/lean burn, but limit the definition to engines designed and manufactured for 1 percent exhaust oxygen:

> "Rich-burn internal combustion engine means a spark ignition internal combustion engine originally designed and manufactured to operate with an exhaust oxygen concentration less than or equal to one percent."

- New Hampshire environmental regulations (NHAR-Env-A 1211.01(an), Effective 5/20/94) have a similar, but not identical regulation. In this case, "rich burn engine" is defined as "any stationary internal combustion engine that is not a lean burn engine." A "lean burn engine" is defined as "a stationary, internal combustion engine in which the amount of O2 in the engine exhaust gases is 1.0 percent or more, by weight, unless otherwise specified by the engine manufacturer."

VIII. CONCLUSIONS

Engines operating rich of the stoichiometric air-to-fuel ratio are clearly rich burn engines. Technically, when engines operate lean of stoichiometric (stoichiometric correlates to approximately 0.5 percent oxygen), they are no longer operating in a rich-burn mode. However, according to engine manufacturers, academics, and air regulations developed for NO_X control, engines operating slightly lean of stoichiometric are considered "rich burn engines." Air regulatory definitions of "rich burn engines" have included engines operating up to 1 percent oxygen, up to 4 percent oxygen, and up to a lambda of 1.1. In addition, recognizing that engines are adjustable, some regulators have tied the definition of "rich burn engines" to manufacturers' recommended air-to-fuel ratio or exhaust oxygen content to limit the opportunity for source owners and operators to adjust the engine so that it is no longer considered a "rich burn."

From the standpoint of the RICE MACT, it is necessary that the standard be achievable for all engines in each subcategory. For SI-NG-4SRB engines, NSCR has been identified as the MACT floor. There may be control options for SI-NG-4SRB engines other than NSCR.

Based on the information presented in this paper, it is clear that the definition of rich burn engines for the RICE MACT standard is complicated and discussions may be summarized as follows:

- With regards to the technical characteristics that should be used to define "rich burn engines," some believe that exhaust oxygen content should be the basis for the definition of "rich burn engines" because it is easily determined in a precise manner in the field and it provides an indication of the engine's air-to-fuel ratio. Others believe that lambda 1.1 should be the basis for the definition of "rich burn engines" because it is independent of fuel, is a technically precise point, and makes compliance determinations definitive.

- With regards to the limits of the definition of "rich burn engines," some believe that "rich burn engines" should include only those engines that can use NSCR as a 3-way catalyst for the simultaneous control of NO_X, CO, and HC. Others believe that "rich burn engines" should include engines beyond those that may use NSCR as a 3-way catalyst, so long as all engines included in the SI-NG-4SRB subcategory could meet the MACT requirements through the use of any device, such as an oxidation catalyst or NSCR used solely for oxidation.

- In order to prevent engine owners/operators from adjusting the operating conditions to avoid rich burn regulatory requirements, some believe it is important to link the definition of "rich burn engines" to the manufacturer's specifications for air-to-fuel ratio or exhaust oxygen content or to include other constraints to limit the temporary adjustment of the engine to avoid rich burn regulatory requirements. Other believe it is important that the definition of "rich burn engines" not rely solely on the manufacturer's specifications and the definition should take into account the possible re-manufacture or re-construction of an existing engine, which may result in engineering and operating characteristics more closely akin to lean burn engines than to rich burn engines. In addition, the definition should accommodate diverse operating conditions, which may result in an exhaust gas oxygen content different than that specified by the manufacturer.

The definition for “rich burn engine” should accomplish the following goals:

- The definition should incorporate engines that operate both fuel-rich and slightly lean of stoichiometry.

- The definition should incorporate other engines only where the control needed to meet the MACT regulation is achievable.

- The definition should recognize that existing engines, originally considered "rich-burn," might have been modified in the field to run at conditions that are significantly lean of stoichiometry.

- The definition should not allow engine owners and operators the opportunity to adjust the engine to lean burn status to avoid rich burn regulatory requirements.

ATTACHMENT VIII

ASSESSMENT OF THE EPA ICCR EMISSIONS DATABASE FOR RECIPROCATING INTERNAL COMBUSTION ENGINES

Industrial Combustion Coordinated Rulemaking (ICCR)
Federal Advisory Committee

September 16, 1998

TABLE OF CONTENTS

I. INTRODUCTION

This paper presents the results of assessment of the EPA ICCR Emissions Database for RICE (RICE Emissions Database). The assessment of the RICE Emissions Database was conducted in the context of determining the adequacy of the emissions data in the database to support the MACT rule development for stationary RICE.

The Emissions Database includes the available emissions data identified to date by EPA to support the ICCR rule development for engines. The ICCR Coordinating Committee has recommended that additional emissions data would better support the ICCR rule development, and EPA is collecting additional emission data at the Colorado State University (CSU) Engines and Energy Conversion Laboratory. The Committee’s recommendation for additional testing was based largely on the review of emissions data included in the ICCR Emissions Database for RICE.

Section II of this paper provides a description of the characteristics of the emissions data currently included in the ICCR Emissions Database for RICE, including a breakdown of the data by subcategory and a summary of the available emissions data for control devices. Section III provides a summary of the results of the ICCR Coordinating Committee’s review of the emissions data in the database. The final section of this paper presents the ICCR Coordinating Committee’s conclusions and recommendations regarding the emissions data included in the database.

II. CHARACTERISTICS OF THE HAPS EMISSIONS DATA INCLUDED IN THE RICE EMISSIONS DATABASE

The RICE Emissions Database (version 2.0) includes 92 test reports, with over 448 emissions tests for stationary RICE -- 171 emissions tests include HAP emissions data, 344 emissions tests include criteria pollutant data, and 67 tests include both HAP and criteria pollutant data. The tests incorporate the measurement of 45 HAPs. For each test report, EPA has calculated emission factors for HAPs in a consistent manner based on the emission concentration reported. When a single test included more than one run, the concentrations reported in each run are averaged. When a test includes HAPs that were not detected at levels above the method's detection limit (non-detects), EPA has calculated emission factors based on a percentage of the method’s detection limit. EPA has flagged those values calculated based on a percentage of the detection limit with a less-than sign (<). If all runs conducted for an emissions test resulted in non-detects, EPA has flagged the data with a double less-than sign (<<). If concentrations were measured in at least one run, and other runs included non-detects, EPA has flagged the data with a single less-than sign (<). EPA included these data flags to identify those emission factors based on non-detects and to facilitate review of these data in the future. A description of the development of the emissions database, including assumptions used in the calculations is provided as Appendix A. The ICCR Coordinating Committee has performed quality assurance reviews of a representative number of the emissions test reports and determined which reports should be considered adequate for general assessment of HAP emissions from stationary RICE. This review is discussed in Section III of this paper.

A summary of the sources of the emissions data in the ICCR Emissions Database is provided below. In addition, a summary of the emissions data included in the database for the RICE subcategories is presented, along with a summary of the emissions data for control devices.

A. Sources of Emissions Data

The RICE Emissions Database was compiled by EPA principally from the following sources:

- Source test reports (compliance tests) identified in EPA's Source Test Information Retrieval System (STIRS),
- Source test reports (compliance tests) submitted by stakeholders in the ICCR process, and
- Emissions tests conducted by the Gas Research Institute (GRI).

No standard protocol was used to conduct the emissions tests included in the RICE Emissions Database. The HAPs reported, test methods used, detection limits, operating conditions tested, and reasons why testing was performed vary significantly from test to test. Most of the STIRS test reports with HAP emissions data come from California air pollution control districts and were conducted by source owners and operators to comply with California's AB2588 air toxic regulation. In those cases, test methods developed and approved by the California Air Resources Board (CARB) are generally used to quantify emissions. The target HAPs for the California tests vary since the target HAPs were negotiated with the local air pollution control district.

EPA has requested copies of additional emissions test reports for stationary RICE from various districts in California. Although the ICCR Coordinating Committee has not reviewed the additional test reports, the Committee recommends that the data from these test reports be included in the RICE Emissions Database. Based on available information, it is anticipated that these test reports will be similar in quality to those compiled by EPA from the California districts.

The database also includes 112 emissions tests conducted by the Gas Research Institute (GRI) for natural gas-fired engines. These emissions tests were conducted by GRI in cooperation with GRI member companies.

B. Emissions Data by Subcategory

The ICCR Coordinating Committee has recommended the following subcategories for existing RICE:

- Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines

- Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines
- Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines
- Spark-Ignition, Digester Gas and Landfill Gas Engines
- Spark-Ignition, Propane, Liquid Petroleum Gas (LPG), and Process Gas Engines
- Spark-Ignition, Gasoline Engines
- Compression-Ignition, Liquid Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)
- Compression-Ignition, Dual Fuel Engines
- Emergency Power Units
- Small Engines (200 brake horsepower or less)

The RICE Emissions Database includes emissions data for all the subcategories recommended, except for Spark-Ignition, Gasoline Engines and Compression-Ignition, Dual Fuel Engines. Engines tested range in size from 54 horsepower (hp) to 5,500 hp. A summary of the number of emissions tests included in the database, by subcategory, is presented in Table 1. Most of the emissions data are for natural gas-fired engines and diesel engines, which, according to the ICCR Population Database, represent over 95 percent of stationary RICE.

For the fuels other than natural gas and diesel, there are a limited number of HAP emissions tests included in the RICE Emissions Database. For the Spark-Ignition, Digester Gas and Landfill Gas subcategory, 14 emissions tests are included in the database for digester gas, and one emissions test is included in the database for landfill gas. For the Spark-Ignition, Propane, LPG, and Process Gas subcategory, 1 HAP emissions test is included in the database for propane (on a small engine) and no HAP emissions tests are included for process gas or LPG. For Compression-Ignition, Liquid-Fuel Engines, all emissions tests included in the RICE Emissions Database are for diesel fuel, and no emissions tests are included for kerosene/naphtha, or heavier fuels, such as residual/crude oil. For the Emergency Power Units subcategory, three emissions tests indicate the engines are generators, but there is insufficient information to determine if they are for emergency use. Two of these tests indicate that multiple engines were included in the tests (common stack) and therefore, it is unclear which engine(s) are represented by the emissions test data.

Table 1. HAP Emissions Tests for Each RICE Subcategory

RICE Subcategory	Emissions Tests
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines[1]	22
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines[1]	32
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines[1]	56
Spark-Ignition, Digester Gas and Landfill Gas Engines	15
Spark-Ignition, Propane, LPG, and Process Gas Engines[2]	0
Spark-Ignition, Gasoline Engines	0
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	26
Compression-Ignition, Dual Fuel Engines	0
Emergency Power Units	Unknown[3]
Small Engines (200 brake horsepower or less)	19

[1] One emissions test for a natural gas-fired engine could not be subcategorized.

[2] One emissions test report, with seven emissions tests, was included in the Database for an engine firing propane. Since the engine is rated at 39 hp, these tests are included in the small engine subcategory.

[3] Three emissions tests were conducted on generators, but the emissions tests do not indicate whether the engines are used for emergency power.

C. <u>HAP Emissions Data for Engines with Criteria Pollutant Control Devices</u>

Most HAP emissions tests included in the RICE Emissions Database were conducted on RICE without emissions controls. In some cases engines with NO_x controls, including pre-combustion chambers (PCC), low emissions combustion (LEC), selective catalytic reduction (SCR), and non-selective catalytic reduction (NSCR), were tested. Also, 6 tests were conducted on engines using oxidation catalysts for carbon monoxide (CO) control. Table 2 includes a summary of the emissions tests for criteria pollutant control devices, by subcategory.

Table 2. HAP Emissions Tests for Criteria Pollutant Control Devices

RICE Subcategory	Criteria Pollutant Control Devices Tested	
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	Non-Selective Catalytic Reduction Pre-Combustion Chamber Pre-Stratified Charge	8 1 1
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	Pre-Combustion Chamber Pre-Stratified Charge Selective Catalytic Reduction	13 2 5
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	Pre-Combustion Chamber Oxidation Catalyst for CO Reduction	3 6
Spark-Ignition, Digester Gas and Landfill Gas Engines	None	
Spark-Ignition, Propane, LPG, and Process Gas Engines	None	
Spark-Ignition, Gasoline Engines	None	
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	Selective Catalytic Reduction	1
Compression-Ignition, Dual Fuel Engines	None	
Emergency Power Units	None	
Small Engines (200 brake horsepower or less)	None	

III. RESULTS OF ASSESSMENT OF THE EMISSIONS DATABASE

The ICCR Coordinating Committee conducted a detailed QA\QC review of the emissions test reports included in the database, largely emissions tests submitted by source owners and operators in California to respond to requirements from State or local air regulatory agencies. The data form included in Appendix B was used as the format for the QA/QC review.

The results of the review of the emissions database may be summarized as follows:

1. Source tests from State and local air regulatory agencies provide “snapshots” of emissions from RICE in real-world applications. The source tests include insufficient information to fully evaluate the operating status of the engine when tested or to draw conclusions about the effects of operating conditions on HAPs. Where possible, EPA contacted the facilities and added information about the engineering parameters of the engines tested. In addition, the information about the engine family was added based on the engine manufacturer and model.

2. The RICE Emissions Database does not contain data to evaluate the effectiveness of catalytic controls, such as non-selective catalytic reduction (NSCR) or oxidation catalysts, throughout the full range of engine operating conditions.

3. Additional emissions data would better support the regulatory development of the RICE MACT standard.

4. Emissions estimates based solely on non-detects should not be used for regulatory purposes. [As noted above, EPA has flagged the emission factors in the ICCR Emissions Database that are based on non-detects.]

5. CARB 430 data from 3 emissions tests for natural gas-fired lean burn engines has evidence of interference. Other emissions tests with CARB 430 data had insufficient information to conclusively determine whether interference had occurred.

A. <u>Emissions Data in Source Tests from State and Local Agencies</u>

Emission levels reported in the source tests are highly variable. For example, emissions of formaldehyde reported in the database for natural gas-fired engines cover six orders of magnitude, from 4.43E-07 pounds per million British Thermal Unit (lb/MMBTU) to 7.23E-01 lb/MMBTU. [The data for lean burn natural gas-fired engines are presented in Figures 1 and 2.] The variability could be attributed to two possible causes: 1) reported formaldehyde levels in some cases may be artificially low due to interference with DNPH-based test methods, and 2) emissions may be affected by the operating condition of the engine when tested.

The tests lack information about the engine process. HAP emissions tests obtained from state and local air regulatory agencies were conducted by source owners and operators in response to air regulatory requirements. Therefore, the goals for the testing were limited to the air regulatory requirements, rather than the goal of documenting emissions throughout the operating range or determining the effects of engine operating conditions on HAP emissions. Tests that provide detailed information about engine emissions throughout the full range of engine operating conditions are not required in the regulatory context, and therefore, tests with that level of detail are not available from state and local air regulatory agencies.

The test reports lack key information about engineering and operating parameters that could affect HAP emissions. For example, the manufacturer and model of the engine are often lacking in test reports. Information about whether the engine was a 2-stroke or 4-stroke cycle is absent. The air-to-fuel ratio is often lacking, as is the horsepower and speed (rated and as tested). In addition, the engines apparently were tested in an “as-found” condition without full consideration of the reciprocating internal combustion process.

There is insufficient information in the test reports to account for the unexplained variability in the emissions data included in the ICCR Emissions Database for RICE. Apparently, there are no existing data for testing a single engine over the entire envelope of operating conditions.

Several key parameters were identified that would be necessary to fully evaluate the emissions data included in the RICE Emissions Database, including the following:

- Fuel used during emissions testing
- Engine manufacturer and model
- Engine subcategory
- Horsepower and speed (rated and as-tested)

Where possible, EPA contacted the tested facilities and obtained missing information. In general, the additional information obtained from the facilities included engine manufacturer and model and rated horsepower and speed. Information about the operating conditions of the engine during the emissions tests generally were not available. Information about engine subcategory was added to the database by using the engine manufacturer and model and information available from the engine manufacturers to determine which subcategory the engine should be placed in.

For those tests that met QA\QC review, the emissions data in source tests from state and local agencies only provided “snapshots” of the HAP emissions from the engines at the time of testing. The emissions tests evidently were not conducted over multiple operating conditions that might be seen by the engine in its application. Also, key information about the engine status was missing from the test reports, and could not be added. While this may have been sufficient for compliance purposes, it is not sufficient for determining HAP emissions throughout the operating range or for determining the effect of engine operating conditions on HAP emissions. Therefore, the ICCR Coordinating Committee recommends that the data is inadequate to fully evaluate the range of emissions that would be anticipated from the unit throughout its operating range. In addition, the data included in the Emissions Database (version 2.0) should not be used to evaluate the effects of operating conditions on HAP emissions.

Emissions data throughout the operating range are necessary to fully evaluate HAP emissions from stationary RICE because engine operating parameters affect the physical and chemical mechanisms that result in the production of formaldehyde and other similar HAPs in ways that are indirect, complicated and often interrelated. For example, for large-bore natural gas-fired engines, increasing load typically increases the captured fuel air ratio, average cylinder temperature and exhaust temperatures, and peak pressure. It also affects mixing, level of turbulence, and flame propagation in unknown ways. This makes any evaluation of the effects of engine operation on formaldehyde both difficult and speculative given the present state of understanding.[9]

B. Emissions Data to Determine Efficiencies of Catalytic Controls

The emissions tests reports were reviewed to determine if there was sufficient information to determine the effectiveness of controls that may reduce HAPs. Based on the review of existing control devices, existing catalytic controls for carbon monoxide (CO) reduction may also oxidize certain HAPs, such as formaldehyde. Non-selective catalytic reduction (NSCR) is a possible MACT control for natural gas-fired 4-stroke rich burn engines. Oxidation catalysts are a possible MACT control for natural gas-fired lean-burn engines and for diesel engines. Catalytic controls were not considered for the Digester Gas/Landfill Gas subcategory because these fuels commonly contain siloxanes and other trace components, which foul catalysts.

The RICE Emissions Database includes eight emissions test for non-selective catalytic reduction (NSCR) on natural gas-fired 4-stroke rich burn engines. There are six emissions tests for oxidation catalysts for lean-burn engines.

There is insufficient data to evaluate the effectiveness of NSCR and oxidation catalysts over the full operating range. The data in the Emissions Database for NSCR include a limited number of pollutants and high detection limits (FTIR with a 0.5 ppm detection limit), so that non-detects were frequently reported. The data in the Emissions Database for oxidation catalysts lack sufficient emissions data before and after the control device to estimate representative control efficiency, and only a small portion of the pollutants were measured before and after controls.

C. Additional Emissions Data Would Better Support the RICE MACT

The ICCR Coordinating Committee recommends that additional emissions data would better support the ICCR rule development. This recommendation was reached as a result of the review of emissions data available to the ICCR process in the EPA ICCR Emissions Database for RICE. The following key emissions data gaps have been identified:

1. Data to determine the effectiveness of after-treatment control devices to reduce formaldehyde and other HAPs;

[9] Factors Affecting the Measurement of CH_2O in Large-Bore Natural Gas Engines, C.E. Mitchell and D.B. Olsen, February 1998, ASME Paper 98-ICE-81, ICE-Vole. 30-1, 1998 Spring ASME-ICE Division Engine Technology Conference.

2. Data to evaluate the effectiveness of combustion modifications to reduce formaldehyde and other HAPs;

3. Data to determine typical emissions for engines throughout the operating range.

The ICCR Coordinating Committee recommended a RICE Test Plan to provide data to assess the effectiveness of after-treatment control devices to reduce formaldehyde and other HAPs. The test plan was designed to address this data gap for the following reasons:

- Emissions data to demonstrate the effectiveness of possible MACT control devices for existing RICE is a data gap in the ICCR Emissions Database for RICE.

- Understanding of the effects of combustion modifications on HAPs is in its infancy, and would require a very extensive research program to identify potential control techniques, along with confirming testing.

The RICE Test Plan also will provide data to partially fill the data gap on baseline emissions from engines, since pre-controlled emissions throughout a 16-point test matrix of operating conditions will be recorded during the testing program.

D. <u>Non-Detect Values</u>

The ICCR Coordinating Committee reviewed the issue of non-detect values and recommends the following:

- No decisions leading to requirements for control devices or emissions limits on combustion processes should be made that are based on emission levels derived from default HAP concentrations calculated from method detection levels.

- Where non-detects are present, they should be carefully documented to ensure that MACT decisions are not made based on non-detect values.

As indicated above, EPA has flagged emission factors in the ICCR Emissions Database that were calculated based on non-detects. Table 3 presents the pollutants, by subcategory, for which all emission estimates in the database are based on non-detects only. Table 4 presents those pollutants, by subcategory, for which some emission estimates are based on non-detects and some emission estimates are based on measured concentrations.

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	1,1,2-Tetrachloroethane	6
	1,1-Dichloroethane	6
	1,2-Dichloroethane	6
	1,2-Dichloropropane	6
	1,3-Dichloropropene	6
	Carbon Tetrachloride	6
	Chlorobenzene	6
	Chloroform	6
	Ethylene Dibromide	6
	Styrene	6
	Vinyl Chloride	6
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	1,1,2,2-Tetrachloroethylene	9
	1,1,2-Tetrachloroethane	9
	1,1-Dichloroethane	9
	1,2-Dichloroethane	9
	1,2-Dichloropropane	9
	1,3-Dichloropropene	9
	Carbon Tetrachloride	9
	Chlorobenzene	9
	Chloroform	9
	Ethylene Dibromide	9
	Vinyl Chloride	9

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only (Continued)

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	1,1,2,2-Tetrachloroethylene	6
	1,1,2-Tetrachloroethane	6
	1,1-Dichloroethane	6
	1,2-Dichloroethane	6
	1,2-Dichloropropane	6
	1,3-Dichloropropene	6
	Carbon Tetrachloride	6
	Chlorobenzene	6
	Chloroform	6
	Ethylene Dibromide	6
	Vinyl Chloride	6
Spark-Ignition, Digester Gas and Landfill Gas Engines (all non-detects are for Digester Gas only)	1,1,1-Trichloroethane	14
	1,3-Butadiene	14
	1,4-Dioxane	14
	Carbon Tetrachloride	8
	Chloroform	14
	Ethylene Dibromide	11
	Ethylene Dichloride	14
	Tetrachloroethylene	14
	Trichloroethylene	14
	Vinyl Chloride	14
	Vinylidene Chloride	14
Spark-Ignition, Propane, LPG, and Process Gas Engines	None	
Spark-Ignition, Gasoline Engines	None	
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	Beryllium	3
	Selenium	3
Compression-Ignition, Dual Fuel Engines	None	
Emergency Power Units	Unknown	

Table 3. Pollutants, by Subcategory, for Which All Emissions Estimates in the Database are Based on Non-Detects Only (Continued)

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only
Small Engines (200 brake horsepower or less)	1,1,1-Trichloroethane (Digester Gas)	3
	1,3-Butadiene (Digester Gas)	3
	1,4-Dioxane (Digester Gas)	3
	Carbon Tetrachloride (Digester Gas)	3
	Chloroform (Digester Gas)	3
	Ethylene Dibromide (Digester Gas)	3
	Ethylene Dichloride (Digester Gas)	3
	Naphthalene (Propane & Natural Gas)	9
	Tetrachloroethylene (Digester Gas)	3
	Trichloroethylene (Digester Gas)	3
	Vinylidene Chloride (Digester Gas)	3

Source: ICCR Emissions Database Version 2.0, LB/MMBtu Report

Table 4. Pollutants, by Subcategory, for Which Some Non-Detects and Some Measured Concentrations Were Reported

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only	Number of Emission Estimates Based on Measured Concentrations
Spark-Ignition, Natural Gas 4-Stroke Rich Burn Engines	1,1,2,2-Tetrachloroethylene	5	1
	Acrolein	6	7
	Acetaldehyde	6	7
	Ethylbenzene	6	5
	Formaldehyde	3	15
	Methylene Chloride	2	4
	Naphthalene	5	3
	Toluene	3	13
	Xylene(s)	6	10
Spark-Ignition, Natural Gas 4-Stroke Lean Burn Engines	Acrolein	11	8
	Acetaldehyde	13	3
	Ethylbenzene	4	10
	Formaldehyde	1	22
	Methylene Chloride	4	5
	Styrene	9	1
	Xylene(s)	1	13
Spark-Ignition, Natural Gas 2-Stroke Lean Burn Engines	Acrolein	31	8
	Acetaldehyde	33	16
	Ethylbenzene	7	9
	Methanol	9	33
	Naphthalene	1	1
	Styrene	6	3
	Xylene(s)	7	11

Table 4. Pollutants, by Subcategory, for Which Some Non-Detects and Some Measured Concentrations Were Reported (Continued)

RICE Subcategory	Pollutant	Number of Emission Estimates Based on Non-Detects Only	Number of Emission Estimates Based on Measured Concentrations
Spark-Ignition, Digester Gas and Landfill Gas Engines	Acrolein	1	13
	Benzene	1	13
	Dichlorobenzene	8	6
	Methylene Chloride	2	12
	Styrene	7	7
	Xylene	1	13
Spark-Ignition, Propane, LPG, and Process Gas Engines	None		
Spark-Ignition, Gasoline Engines	None		
Compression-Ignition, Liquid-Fuel Engines (diesel, residual/crude oil, kerosene/naphtha)	1-3, Butadiene	1	1
	Formaldehyde	8	17
	n-Hexane	1	1
Compression-Ignition, Dual Fuel Engines	None		
Emergency Power Units	Unknown		
Small Engines (200 brake horsepower or less)	Acrolein (Digester Gas)	1	5
	Vinyl Chloride (Digester Gas)	2	1

Source: ICCR Emissions Database Version 2.0, LB/MMBtu Report

E. CARB 430 Data for Natural Gas-Fired Lean Burn Engines

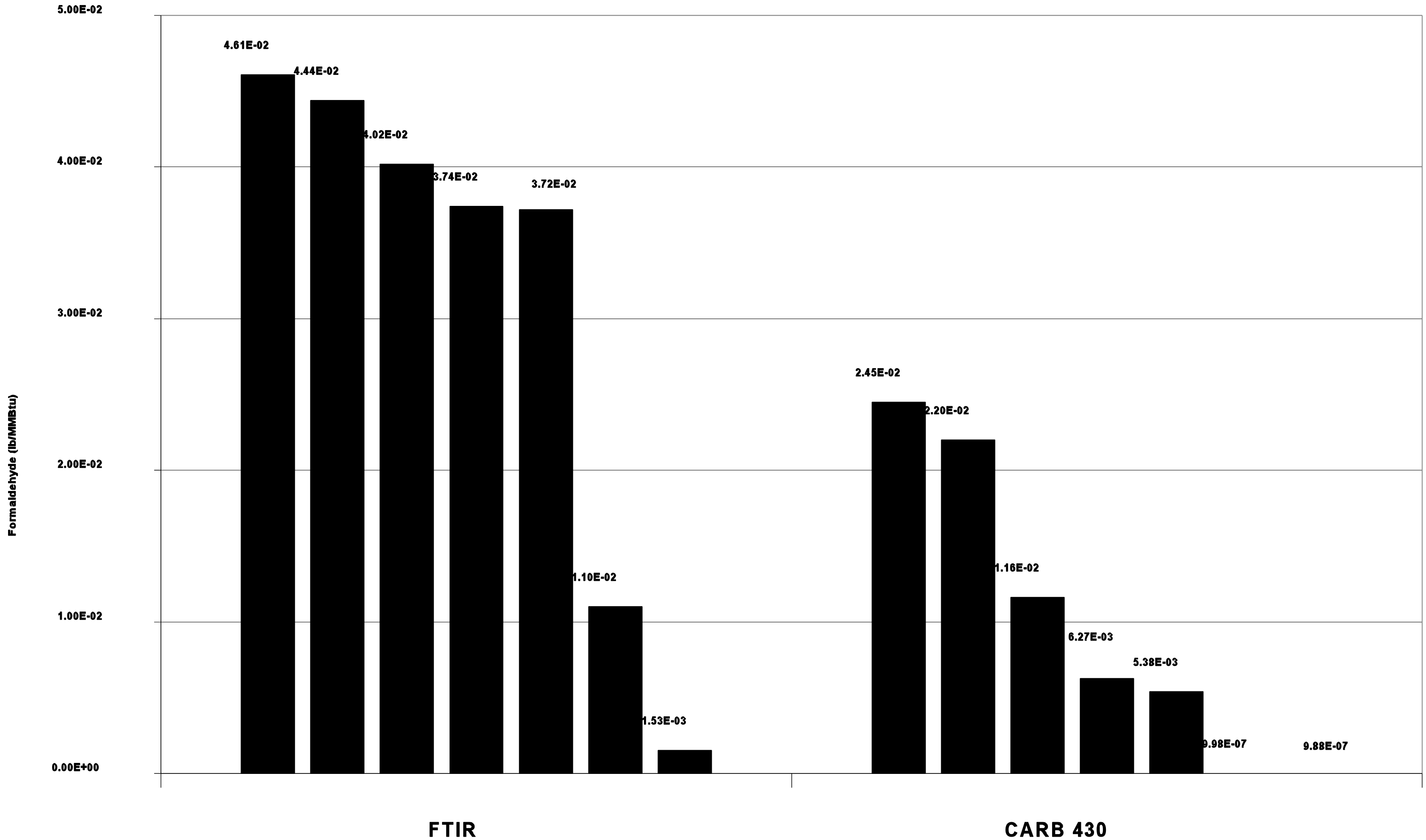
The ICCR Coordinating Committee reviewed the issue of formaldehyde data for natural gas-fired lean-burn engines collected using methods, such as CARB 430, that rely on a DNPH solution to quantify formaldehyde concentrations. The Gas Research Institute (GRI) first advised EPA that there could be NO_2 depletion of the DNPH solution when DNPH-based methods are used on natural gas-fired lean-burn engines. In the case of high NO_2 levels, the DNPH may be depleted so that formaldehyde levels for lean-burn engines are underreported. GRI had noted the problem when conducting side-by-side testing with its EPA-approved method, using FTIR, and the CARB 430 method, using a DNPH solution. CARB 430 data is included in the RICE Emissions Database for both 4-stroke lean burn and 2-stroke lean burn natural gas-fired engines.

The Committee requested that EPA compare the CARB 430 data for natural gas-fired lean burn engines to data collected for lean burn engines using FTIR. Based on EPA's review, a total of 3 emissions tests, of 16 tests reviewed, included adequate information to determine that there was a problem with the CARB 430 data. These emissions tests have been tagged with an "x" in the database (for pollutants measured with CARB 430) to indicate that the emissions tests do not include acceptable HAP emissions data for those pollutants measured with CARB 430.

EPA reported that the 13 other emissions tests conducted with CARB 430 did not contain sufficient information to determine definitively that there was interference with the method. EPA also conducted a preliminary statistical analysis of the CARB 430 data. Based on that preliminary analysis, EPA concluded that the remaining data from CARB 430 and FTIR for 4-stroke lean burn and 2-stroke lean burn engines are equivalent. The ICCR Coordinating Committee does not necessarily concur with EPA's conclusion that the data are equivalent and some believe that questions remain about the CARB 430 data for natural gas-fired lean burn engines and that further analysis of the data is warranted.

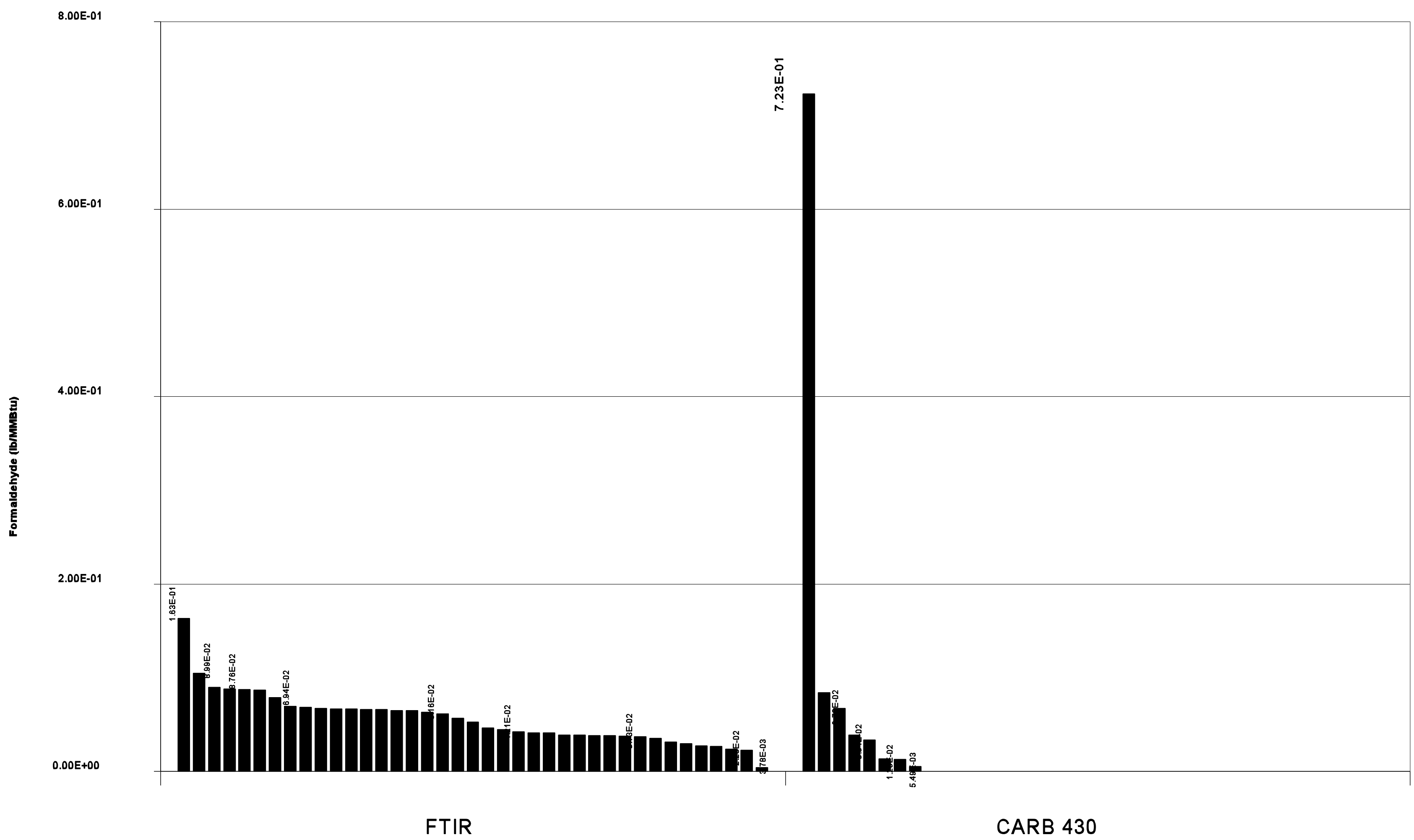
The formaldehyde emissions data included in the RICE Emissions Database for natural gas-fired 4-stroke lean burn engines is presented in Figure 1. The formaldehyde emissions data included in the database for natural gas-fired 2-stroke lean burn engines is presented in Figure 2.

Figure 1. Formaldehyde Values for Natural Gas-Fired 4-Stroke Lean Burn Engines



(data presented are from independent testing, not simultaneous testing)

Figure 2. Formaldehyde Data for Natural Gas-fired 2-Stroke Lean Burn Engines



(data presented are from independent testing, not simultaneous testing)

IV. CONCLUSIONS AND RECOMMENDATIONS

The ICCR Coordinating Committee concludes that additional emissions data would better support the ICCR rule development for the following reasons:

- Variability of the emissions data in the RICE Emissions Database cannot be explained with available information.

- Information about the engine process during emissions testing from state and local agencies is insufficient to understand how emissions vary over full operating range.

- Emissions data before and after catalytic control devices that may reduce HAP emissions, including NSCR and oxidation catalysts, is inadequate to evaluate the effectiveness of those devices on reducing HAP emissions throughout the full operating range.

- There are questions remaining about existing emissions data for natural gas-fired lean-burn engines from tests using CARB 430 and other DNPH-based methods (where NO_2 may have depleted the DNPH solution). The ICCR Coordinating Committee also recommends that FTIR be used to measure formaldehyde emissions in future EPA emissions testing for natural gas lean burn engines.

The ICCR Coordinating Committee recommends that EPA rely on data from the RICE Test Plan recommended by the Committee and similar data of that caliber to assess the efficiency of HAP emissions control technology, such as NSCR and oxidation catalysts, throughout the full operating range. Although the RICE Emissions Database does not adequately address the issues listed above, there still may be appropriate uses for the data as a part of the regulatory development for RICE. The data does provide “snapshot” emissions data for a variety of stationary RICE. This data is relevant to EPA’s analysis of the achievability of any emission limitations under consideration for the RICE MACT.

APPENDIX A

HAP Emission Data Calculations for RICE Emissions Database

APPENDIX A

HAP Emission Data Calculations for RICE Emissions Database

EPA developed a Microsoft Access database for HAP emissions data for reciprocating internal combustion engines. The RICE Emissions Database includes the measured emissions concentrations and all other parameters necessary to calculate emission rates and factors. The database also includes physical and operational parameters which may affect HAP emissions. A total of 1386 records from 30 test reports are included in the database. Each record contains information from up to three test runs for an identified HAP.

Unreported emissions are presented as “NR.” Unreported emissions are the result of missing parameters such as pollutant concentration, fuel type, engine type and size, stack exhaust flowrate, or fuel consumption levels. Typically, each test consisted of three test runs. For the tests where at least one run (but not all runs) revealed an undetected concentration, a “<” sign precedes the calculated emission rates and factors. In cases where the pollutant was not detected in all test runs, the emission concentrations are presented as “ND”, and a “<<” sign precedes the calculated emission rates and factors. All emission rates and factors corresponding to undetected concentrations are calculated based on the reported pollutant detection limit.

The emission factors and rates were determined using EPA recommended calculations. Emissions factors in lb/MMBtu were determined according to EPA Method 19 referenced in 40 CFR part 60, Appendix A. These factors are based on the measured pollutant concentration, fuel factor, and stack oxygen levels. Emission rates in lb/hr were determined using standard engineering calculations and are based on the measured pollutant concentration, exhaust stack flow rate, and the exhaust temperature. Emission factors in lb/HP-hr were based on the calculated emission rates (lb/hr), engine rating (HP), and load conditions. In cases where the fuel factor was not provided, EPA used the fuel factors provided in 40 CFR 60. It should be noted that the 40 CFR 60 fuel factors are within 3 percent of the average reported fuel factors for natural gas, and within 2 percent of the average reported fuel factors for diesel fuel.

Emissions factors were calculated according to Equations 1 through 5 below. For gaseous HAPs, Equations 1 and 2 were used to calculate emission rates in lb/hr and emission factors in lb/MMBtu, respectively. For particulate HAPs, Equations 3 and 4 were used to calculate emission rates in lb/hr and emission factors in lb/MMBtu, respectively. Equation 5 was used to calculate emission factors in lb/HP-hr for both gaseous and particulate HAPs. Load conditions are incorporated into Equation 5 to account for engine output power.

Equation 1: Emission Rate in (lb/hr) for gaseous HAPs:

$$ER\left(\frac{lb}{hr}\right) = \frac{1.369x\,10^{-9}\left(\frac{lb - mol^{o}\,R}{ft^{3}}\right) x\; 60\left(\frac{\min}{hr}\right) x\; Q_{stk}\left(\frac{dscf}{\min}\right) x\; C\,(ppb)\; x\; M\left(\frac{lb}{lb - mol}\right)}{(T_{std} + 460\;)^{o}\,R}$$

where: ER = Emission rate (lb/hr)

Q_{stk} = Stack gas flow rate (dscf/min)

C = Measured concentration (ppb)

M = HAP molecular weight (lb/lb-mol)

T_{stk} = Stack temperature (^{o}F)

Equation 2: Emission Factor in (lb/MMBtu) for gaseous HAPs:

$$EF_{F}\left(\frac{lb}{MMBtu}\right) = \frac{1.369x\,10^{-9}\left(\frac{lb - mol^{o}\,R}{ft^{3}}\right) x\; F_{F}\left(\frac{dscf}{MMBtu}\right) x\; C\,(ppb)\; x\; M\left(\frac{lb}{lb - mol}\right) x\; \frac{20.9}{20.9 - \%\,O_{2}}}{(T_{std} + 460\;)^{o}\,R}$$

where: EF_F = Emission factor (lb/MMBtu)

F_F = Fuel factor (dscf/MMBtu)

$\%O_2$ = Percent oxygen in the stack

Equation 3: Emission Rate in (lb/hr) for particulate HAPs:

$$ER\left(\frac{lb}{hr}\right) = 3.70x\,10^{-9}\,C\left(\frac{\mu g}{dscm}\right)\,X\;Q_{stk}\left(\frac{dscf}{\min}\right)$$

where: C = Measured concentration (μg/dscm)

Equation 4: Emission Factor in (lb/MMBtu) for particulate HAPs:

$$EF_F\left(\frac{lb}{MMBtu}\right) = 6.23x\;10^{-11}\;X\;C\left(\frac{\mu g}{dscm}\right)\;X\;F_F\left(\frac{dscf}{MMBtu}\right)\;X\;\frac{20.9}{20.9 - \%\,O_2}$$

where: C = Measured concentration (μg/dscm)

Equation 5: Emission Factor in (lb/HP-hr) for both gaseous and particulate HAPs:

$$EF_P(lb/HP - hr) = \frac{ER\,(lb/hr)}{P\,(HP)\,x\left(\frac{Load}{100}\right)}$$

where: EF_p = Emission factor based on power output (lb/HP-hr)
P = Power output (HP)
Load = Load conditions of the tested engine**.**

APPENDIX B

Industrial Combustion Coordinated Rulemaking

Stationary Reciprocating Internal Combustion (IC) Engines

Format for QA/QC Review of RICE Emissions Database

Part I: General Facility Information

1. **Facility identification number from NEDS, if available:____**
   If the facility ID from NEDS is not available, provide a facility ID for use on this form:____________________

2. **Name of legal owner of facility:____**

   ____

3. **Name of legal operator of facility, if different from legal owner:____________________________**

   ____

4. **Address of legal owner or operator:____**

   ____

   ____

5. **Size of company:**
   a. **Approximate number of employees of the business enterprise that owns this facility, including where applicable, the parent company and all subsidiaries, branches, and unrelated establishments owned by the parent company (answer may be given using the following ranges: 0-100; 101-250; 251-500; 501-750; 751-1,000; 1,001-1,500; or >1,500):**

   ____

   b. **Number of facility employees:____**

6. **Name of facility:____**

7. **Type of facility:**
   a. **Description of type of facility:____**
   b. **Standard Industrial Classification (SIC) Code:____________________________________**

8. **Size of facility:**
   a. **Total number of stationary reciprocating IC engines at the facility (50 bhp or greater):____________**
   b. **Total stationary horsepower (reciprocating IC engines 50 bhp or greater only):______________bhp**

9. **Location of facility:**
   a. **Name of County (or Parish) where facility is located:________________________________**
   b. **Complete street address of facility (physical location):______________________________**
   c. **Complete mailing address of facility (if different from street address):______________________**

10. **Name and title of contact(s) able to answer technical questions about the completed survey:**

11. **Contact telephone number: (_______)______________ Fax: (__)____________e-mail:________________________**

PART II: Stationary Reciprocating Internal Combustion Engine Information

Please indicate the total number of stationary reciprocating internal combustion engines at the facility for each of the size classifications (per unit) included in the table below:

Rated Horsepower of Engine	Total Number of Stationary Engines at Facility	Number of Engines Listed in Previous Column that are Used for Emergency Standby Only
50-150		
151-300		
301-500		
501-750		
751-1000		
1001-1500		
1501-2000		
>2000		
Total Number of Engines		

For each engine included in the above table, please complete the Part III -- Engineering Information and Part IV -- Typical Operating Information forms, unless some units are identical. Identical units may be reported on the same Part III and Part IV forms. If identical units are reported on the Part III and Part IV forms, provide engine identification numbers for all units included on the same form. For the purposes of this survey, units may be considered identical only if all the following criteria are met:

a. All units have the same manufacturer and model number.

b. All engineering data for the units are the same.

c. All operating data for the units are the same.

d. The primary use of all the units is the same.

Photocopy this section in order to complete one Part IV -- Typical Operating Information form for each stationary reciprocating internal combustion engine listed in the table in Part II. Identical units may be reported on the same form.

Part III: Engineering Information

1. Identification number(s) assigned by the facility for reciprocating IC engines reported on this form, e.g., Engine 001:______

2. Manufacturer Information:

a. Engine Manufacturer:____

b. Engine Manufacturer's Model:____

3. Year Installed:___________Has the combustion related hardware been changed since manufacture?

☐ yes ☐ no If so, when was the hardware changed:________ Attach a brief description of what was done.

4. Engine Descriptors:

a. Ignition: ☐ Spark Ignition (SI) ☐ Compression Ignition (CI), i.e., Diesel

If SI, is the engine: ☐ Rich Burn ☐Lean Burn

b. Stroke: ☐ 2-stroke cycle ☐4-stroke cycle

c. Primary fuel: ☐ Liquid ☐ Gaseous ☐ Dual Fuel (pilot injection CI only)

5. Please provide the following information which typically is available from the engine nameplate (note that certain of these values may be different from the operating values):

a. Bore:____________________________inches or mm (circle one)

b. Stroke:___________________________ inches or mm (circle one)

c. Displacement:____________________cubic inches or liters (circle one)

d. Rated Speed:_____________________ rpm

e. Rated Power:_____________________bhp or kW (circle one)

f. Compression Ratio:________: 1

g. Spark timing (SI):________________° BTDC or injection timing (CI):________° BTDC

h. Manufacturer's Serial Number(s):____

6. Engine Configuration:

a. Cylinders: ☐ In-line ☐ Vee number of power cylinders:____________________

b. Engine aspiration (breathing):

i. If 2-stroke cycle: ☐ Blower Scavenged

☐ Piston Scavenged

☐ Pump Scavenged

Is it also: ☐ Turbocharged ☐ Turbocharged with aftercooling/intercooling ☐ Neither

ii. If 4-stroke cycle: ☐ Naturally Aspirated

☐ Turbocharged/Supercharged

☐ Turbocharged/Supercharged with aftercooling/intercooling

c. If equipped with aftercooling/intercooling, what is the design cooling water temperature?

☐ 85° F (29.5° C) ☐ 130° F (54.5° C) ☐ Other -- specify ___° F or ° C (circle one)

7. Primary engine use (please check one only):

☐ Electric power generation (e.g., prime power or peak shaving)

☐**Co-generation (electricity plus heat)**
☐ **Steam or heat generation only**
☐ **Mechanical power (e.g., pump, blower, compressor, etc.)**
☐ **Transport of a liquid or gas (e.g., pipeline transmission)**
☐ **Waste destruction (e.g., combustion of landfill or process byproduct gas)**
☐ **Emergency only (electrical or mechanical -- circle one)**
☐ **Other -- Please describe:__________________**

Facility ID number:______________________ Company ID number(s) for reciprocating IC engine(s):_______________________________

Photocopy this section in order to complete one Part IV -- Typical Operating Information form for each stationary reciprocating internal combustion engine listed in the table in Part II. Identical units may be reported on the same form.

Part IV: Typical Operating Information

Provide typical operating information on this form for each stationary reciprocating IC engine included in the Table in Part II. Please note that these values may be different from the rated or design data provided on the Part III -- Engineering Information form.

1. Hours of Operation (hr/yr): Typical:_______________ Maximum:_________________

2. Frequency of startups/shutdowns (no./yr): Typical:_______________ Maximum:_________________
Hours during startups/shutdowns: Typical:_________________ Maximum:________________

3. Degree of automation: (check all that apply)
☐ manual ☐ local automatic ☐ remote automatic

4. Engine operating parameters (please note that certain of these values may be different from the rated values reported on the manufacturer's nameplate):

- **a. Operating Speed:___________________rpm**
- **b. Operating Power:__________________ bhp or kW (circle one)**
- **c. Spark timing (SI):__________________° BTDC or injection timing (CI):____________° BTDC**
- **d. Air to Fuel Ratio:___________________ by mass or by volume (circle one)**
- **e. BMEP_____________________________psi or bar (circle one)**
- **f. Peak Firing Pressure:_______________ psi or bar (circle one)**
- **g. Average Heat Input:________________ MMBtu/hr LHV or HHV (circle one) at_________ bhp**
- **h. Maximum Heat Input:______________ MMBtu/hr LHV or HHV (circle one) at _________ bhp**
- **i. Steam generation:__________________ MMBtu/hr (co-generation units only)**

6. Stack parameters: before or after control device (circle one):_______________________________________

- **a. Exhaust Gas Flow Rate:_____________ dscfm at __________________________________ bhp**
- **b. Exhaust Temperature:______________ ° F at ____________________________________ bhp**
- **c. Oxygen Concentration:_____________% by vol. at ______________________________ bhp**

7. Are emissions control device operated for this unit? ☐ yes ☐ no If so, please enter the control device identification number(s) assigned by the facility____

8. Fuel used during normal operations (attach typical fuel analyses if available):

Fuel Use	Fuel Code	LHV of HHV Btu/SCF - Btu/gal (circle one)	% NMHC mass or vol. (circle one)	Pretreatment	Analysis Provided
Operating Fuel (1)	____________	______________	_________	☐ yes* ______	☐ yes
Operating Fuel (2)	____________	______________	_________	☐ yes* ______	☐ yes
Operating Fuel (3)	____________	______________	_________	☐ yes* ______	☐ yes
Startup Fuel	____________	______________	_________	☐ yes* ______	☐ yes
Standby Fuel	____________	______________	_________	☐ yes* ______	☐yes

Fuel Codes:
NG = Natural Gas LG = Landfill Gas GL = Gasoline RG = Refinery Gas
DF = Diesel Fuel BF = Process Byproduct DG = Digester Gas
CO = Crude Oil MX = Mixture:____
OT = Other:____

*** Please provide the pretreatment code from the list below. If a pretreatment code is not listed for the device or method of pretreatment, please enter OT for "Other" and attach a brief description.**

Pretreatment Codes: (Need to provide these)

Facility ID number:_________________ Company ID number(s) for reciprocating IC engine(s):______________________________

Photocopy this section in order to complete one Part V form for each emissions control device in service for the stationary reciprocating internal combustion engines listed in the table in Part II. Identical units may be reported on the same form.

Part V: Emissions Control Device Information

1. Control device identification number assigned by the facility, e.g., CD 001:__________________________

2. Does this control device control emissions from more than one IC engine? ☐ yes ☐ no
Identification number(s) for the reciprocating IC engine(s) served by this control device:______________

____

3. Type of Emissions Control (check all that apply):

___ Air to Fuel Ratio　　___ Catalytic Reduction　　___ Retrofit Low Emission Combustion
___ Catalytic Oxidation　　___ Ignition Timing　　___ Pre-stratified charge
___ Miscellaneous Control Devices, describe:____

4. Manufacturer Information:
- **a. Emissions Control Device Manufacturer:____**
- **b. Model:____**

5. Year Installed:___________ Has permanent hardware been changed since manufacture? ☐ yes ☐ no
If so, when was the hardware changed:______________ Attach a brief description of what was done.

6. Control Efficiency:

Pollutant Controlled	Pre-Control Conc.* (ppm)	Post-Control Conc.* (ppm)	@15% O2	Other

* If the control device is low-emission combustion and the unit was purchased with the low emission combustion equipment, please provide only the post-control concentration.

7. Waste Streams Generated Due to Control Device Operation:

Waste Stream	Amount Per Year	Amount Disposed	Recycling Method
liquid wastewater			
liquid:____________			
solid:_____________			
solid:_____________			

8. Control Costs:
- **a. Capital costs for emissions control device:________________________**
- **b. Annual costs for emissions control device:________________________**
- **c. Do you have detailed cost information? ☐ yes ☐ no If so, would you be willing to provide that cost information at a later time? ☐ yes ☐ no**

ID number(s) for reciprocating IC engine(s) served by the control device:____

Facility ID number:__ ID number for control device:____

Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Criteria Pollutants

NOTE: No New Testing is Required or Requested.

Report all limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column in the table below. If no testing has been conducted for a pollutant listed in the table below, please draw a line through the pollutant name and mark an **"X"** in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	**Permitted Emissions Limit**[a]	**Measured Emissions**[b]	**Fuel Flow** (specify MCF or MMBtu/hr at LHV or HHV)	**Date(s) of Test(s)**	**O2 Level During Test (% dry)**	**Engine Load During Test (specify bhp or % rated bhp)**	**Test Method**[c]	**Number of Tests Included**[d]
CO	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
NOx	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
PM-10	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
SO2	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
VOC	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.
[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.
[c] Indicate the method 1) CEM; 2) Stack test, include test method, such as EPA Method 20, CARB Method 17; or 3) Other, include explanation.
[d] Provide the number of tests averaged to obtain the reported values.
[e] Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ______________________________ Company ID number for reciprocating IC engine:____

Fuel ID for fuel inuse during testing: ________________

Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Hazardous Air Pollutants

NOTE: No New Testing is Required or Requested.

Report all limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column in the table below. If testing was conducted for a pollutant listed in the table, but the pollutant was not detected, report **"ND"** for "not detected" in the **Measured Emissions** column. If no testing has been conducted for a pollutant listed in the table below, please draw a line through the pollutant name and mark an **"X"** in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	**Permitted Emissions Limit**[a]	**Measured Emissions**[b]	**Fuel Flow** (specify MCF or MMBtu/hr at LHV or HHV)	**Date(s) of Test(s)**	**O2 Level During Test (% dry)**	**Engine Load During Test (specify bhp or % rated bhp)**	**Test Method**[c]	**Number of Tests Included**[d]
Acetaldehyde	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Acrolein	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Benzene	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Dioxin	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
Formaldehyde	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.

[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.

[c] Indicate the method 1) CEM; 2) Stack test, include test method used, such as EPA Method 0011, Method CARB 430; or 3) Other, include explanation.

[d] Provide the number of tests averaged to obtain the reported values.

[e]Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ______________________________ Company ID number for reciprocating IC engine:____

Fuel ID for fuel inuse during testing: ________________

Photocopy this section in order to complete one Part VI form for each reciprocating internal combustion engine for which emissions data is available.

Part VI: Emissions Information: Hazardous Air Pollutants (continued)

NOTE: No New Testing is Required or Requested.

Report emissions for all other HAPs in the table below. A list of HAPs is provided as Attachment 1. Report all permit limits included in current air permits in the **Permitted Emissions Limit** column in the table below. Report all **actual measured data** from air emissions tests in the **Measured Emissions** column. If testing was conducted for a pollutant, but the pollutant was not detected, record the pollutant in the table below and report **ND** for "not detected" in the **Measured Emissions** column. Do not report emissions based on emission factors provided by EPA, state or local agencies, or industry associations. If available, please submit a copy of the test report from which the data were obtained.

(If more than one device was vented through the stack on which measurements were made, please explain on a separate sheet.)

Pollutant	**Permitted Emissions Limit**[a]	**Measured Emissions**[b]	**Fuel Flow** (specify MCF or MMBtu/hr at LHV or HHV)	**Date(s) of Test(s)**	**O2 Level During Test (% dry)**	**Engine Load During Test (specify bhp or % rated bhp)**	**Test Method**[c]	**Number of Tests Included**[d]
____________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
____________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
____________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
____________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						
____________	ppm[e] lb/hr g/bhp-hr	ppm[e] lb/hr g/bhp-hr						

[a] Report all permitted emission limits that apply.

[b] Report any measured emission rates that are available. Do not report emissions information based on emission factors provided by EPA, or local agencies, or industry associations.

[c] Indicate the method 1) CEM; 2) Stack test, include test method used, such as EPA Method 0011, Method CARB 430; or 3) Other, include explanation.

[d] Provide the number of tests averaged to obtain the reported values.

[e] Pollutant concentrations reported as ppm should be reported as parts per million by volume on a dry basis, corrected to 15 percent oxygen content.

Facility ID number: ____________________________ Company ID number for reciprocating IC engine: ____

Fuel ID for fuel inuse during testing: _______________

APPENDIX C

Formaldehyde Measurements By The DNPH Methods

APPENDIX C

Formaldehyde Measurements By The DNPH Methods

A. Validity of data in the EPA Database

Studies carried out by Radian International for the Gas Research Institute (GRI) have raised questions regarding the validity of aldehyde emission measurements using the CARB 430 procedure. The industry uses CARB 430, EPA 0011, and related 2,4-dinitrophenyl hydrazine (DNPH) colorimetric procedures to measure formaldehyde emissions from combustion sources. Much of the aldehyde emission data that are available for EPA rule formulation were collected using DNPH procedures.

The Radian report shows evidence that the problem is related to NO_2 (not to be confused with NO or NOx) in the exhaust gas. DNPH reacts with all aldehydes to form derivatives which are then separated and analyzed by liquid chromatography. Radian has also found that DNPH also reacts with NO_2 to form a derivative. This side reaction with NO_2 can lead to depletion of the DNPH or produce other substances that mask the color that is produced by the aldehyde-DNPH reaction.

The GRI reported only comparative measurement between the Fourier Transform Infrared (FTIR) analyzer and CARB 430 for natural gas fired internal combustion engines and found discrepancies between data from the two methods only with lean or clean burn engines. The GRI stated that they have "...no evidence of problems with their CARB 430 applications to natural gas-fired boilers, heaters, turbines or rich burn engines." Their data also showed that their CARB 430 data was always in agreement with the FTIR results when the exhaust gas had less that 60 ppm of NO_2. Their data does not suggest that CARB 430 data should be rejected on the basis of NO_2 interferences as long as the exhaust gas contains no more than 60 ppm NO_2 in the flue gas.

During review of the Radian study, it became evident that Radian used formaldehyde concentrations found by FTIR to determine the sampling volumes used for the CARB 430 measurements in order to ensure that sufficient excess of DNPH would be present to react with formaldehyde. Since at that time they had not yet learned of the NO_2 interference, they inadvertently used too large a sampling volume. A closer review of CARB 430 indicates that the method does not specify volume of stack gas to be sampled. It is therefore possible that some of the data present in the EPA data base collected by CARB 430 may indeed be valid, even if the NO_2 levels were high. However, in the absence of specific information about NO_2 levels and sampling volumes for these tests, it is likely that these tests underestimate formaldehyde emissions from lean or clean burn engines.

B. Future Tests with DNPH Methods

The results of these field test show that formaldehyde emissions are likely to be understated when determined by routine application of CARB 430 to lean or clean burn engines emitting high levels of NOx, in particular NO_2 . Operators of these type of sources should check their NO_2 emissions prior to doing any formaldehyde measurements to see if they have a potential problem. This can be accomplished using a portable NOx analyzer that provides NO and NO_2 data. The test contractor may than be able to adjust the sampling volume accordingly in order to avoid depletion of the DNPH by NO_2 .

Recent laboratory tested reported to GRI have succeeded in reproducing the step change decrease in formaldehyde concentrations when NO_2 concentration exceed 60 ppm. This was achieved by having the gas matrix containing formaldehyde and NO_2 more closely resemble that present in actual combustion gas emissions (i.e., including CH_4, CO, CO_2, NO, etc).

The DNPH procedures should not be rejected for future testing applications because of interferences that were observed with the lean and clean burn two-cycle internal combustion engines. Future testing is expected to result in an improved DNPH method which avoids interference present in emissions with high NO_2 levels. In addition, industry is also evaluating alternative procedures such as the Ashland method, a DNPH impregnated sorbent cartridge, and the Celanese method, an aqueous impingers techniques that measure total aldehydes.

ATTACHMENT IX

ABOVE THE FLOOR MACT FOR DIGESTER AND LANDFILL GAS RECIPROCATING INTERNAL COMBUSTION ENGINES

Industrial Combustion Coordinated Rulemaking
Federal Advisory Committee

September 16, 1998

Above the Floor MACT For Digester And Landfill Gas Reciprocating Internal Combustion Engines

Background

Digester and landfill gases are gaseous by-products, principally comprised of methane and carbon dioxide, of anaerobic decomposition of organic materials. Trace quantities of other compounds are typically found in the gases including hydrogen sulfide and ammonia. In addition, a class of compounds called Siloxanes, which are silicon based compounds found in many cosmetics and cleaning solutions are also present in the gas. These compounds have been known to clog catalysts typically used for post-combustion control of Nitrogen Oxides (NO_X).

These fuels are typically recovered by the facility operators and burned in combustion devices such as internal combustion engines to either generate electricity or directly power a pump or blower.

Survey of Population

A survey was conducted by the Association of Metropolitan Sewerage Agencies (AMSA), which represents the nations largest wastewater treatment agencies, in 1997 to identify what internal combustion engines were operating on digester gas and the type, if any, of controls that were installed to reduce HAP emissions. The results of the survey identified 169 engines (both lean and rich burn types) that burn digester gas. Of these 169 engines, two engines reported operating post-combustion control devices, specifically, Selective Catalytic Reduction (SCR). The other 167 engines reported no post-combustion control; however, many of these engines reported having combustion modifications for the control of NO_X, including pre-combustion chamber, air/fuel ratio adjustment or timing adjustment. None of these combustion modifications have any documentation that demonstrates HAPs reductions. The results of this survey do not appear in the current EPA population database. However, AMSA has submitted their database in a format consistent with the EPA database, and EPA has indicated to AMSA that their data will be incorporated into EPA's database in the future.

The EPA population database used in the ICCR identified 174 engines that burn either landfill gas or digester gas. Of the 174 engines, 3 burn digester gas. For all three digester gas engines, no controls for HAPs were in place.

Of the 171 engines identified in the EPA population database that burn landfill gas, a small percentage of the engines use an "air injection" emission control system on rich-burn engines. Apparently three landfills in California, operated by the same company, operate 10 rich-burn engines that utilize air injection to reduce Carbon Monoxide (CO) emissions. This emission control system was evaluated and is considered inappropriate for reasons discussed in a later section of this paper. In addition, one landfill in Orange County has installed a new control technology system that combines a lean burn engine and afterburner flare that treats the exhaust of a lean burn engine. Since the flare operates at a temperature in excess of 1500 degrees Fahrenheit

(^{o}F), there is the potential that this technology may reduce HAP emissions, and therefore should be further investigated.

As a result of review of existing technologies that have been applied on either digester gas or landfill gas engines, this paper will briefly summarize the applicability of three HAP control technologies to these fuels. These include catalytic control (NSCR or oxidation), air injection, and afterburner flaring.

Above-The-Floor Control Technologies

Catalytic Control

Publicly Owned Treatment Works (POTWs) have had a history of failed applications of catalytic control on digester gas fired engines. This includes both reductive and oxidative catalysts. The primary problem with catalyst is that a compound called Siloxane, which is silicon based and present in both digester and landfill gases, clogs the catalyst bed reducing the availability of sites where the catalytic reaction can occur, and ultimately renders the catalyst inoperable. It should be noted that installation of a pretreatment system to remove the Siloxane prior to combustion in the engine is possible, and will allow a catalytic control system to operate on digester and landfill gases. However, the cost to install and maintain such a system is substantial and is the reason why these pretreatment systems are not currently operating anywhere in the country. Case in point, a POTW in San Diego, which had installed an SCR system for NO_X control on their engine, had installed a pretreatment system, which consisted of water drop out, physical screening and activated carbon, to remove the Siloxane prior to combustion in the engine. The system apparently worked, however, capital and operating costs were high and the facility decided to replace this system (in 1998) with a low-NO_X lean burn engine.

Several case studies on the failure of catalytic controls on digester gas fired engines are briefly described below.

1. A report from Malcolm Pirnie (engineering consultant) to New York's Nassau County Department of Public Works. This report describes the reliability problems with oxidation catalysts applied to digester gas fired engines operating at two different wastewater treatment plants. Based upon testing conducted in 1996, the engines catalyst's performance dropped to 80% efficiency after only 250 hours of operation and it became completely de-activated after approximately 700 hours of operation. The problem was identified as catalyst clogging due to Siloxane. The report also includes a discussion on several other applications of failed catalyst on engines and gas turbines burning digester gas.

2. A report by the City of Los Angeles' (CLA) Technology and Resource Recovery Division on testing of various oxidation catalysts in 1992 treating the exhaust stream of a gas turbine generator. The testing was conducted for the purpose of complying with a local air district rule for criteria pollutants and included an evaluation of seven different catalysts manufactured by five different companies. The study included evaluations of overall catalyst activity after 4,058 hours of service, evidence of

physical masking, and evidence of catalyst poisoning. In the tests, the catalysts from two manufacturers failed, one catalyst manufacturer elected not to test the activity of their catalyst, and two catalyst manufacturers reported high catalyst activity after service (Kleenaire for a base metal on ceramic substrate and MetPro for both a base metal on ceramic substrate and precious metal on ceramic substrate). The CLA's conclusion was that a precious metal catalyst on a ceramic bed could work. However two precious metal catalysts on ceramic substrate were tested (Engelhard and MetPro) and one worked and the other failed. The factors that led to the one successful test are not clear. The CLA elected not to install the catalyst so there are no data available to show full scale successful application.

3. A 1984 report by the Los Angeles County Sanitation Districts (LACSD) on NSCR tests conducted on a digester gas fired engine. Conclusions from the test are that the catalyst did not operate reliably and could not meet the emission limits required by the local air district. The exact cause of the catalyst failure was not identified; however, silicon was detected in significant quantities on the catalyst bed.

4. A memorandum (with attached letters from catalysts manufacturers) from the LACSD summarizing catalyst manufacturers rejection to bid on supplying an SCR system for a turbine firing digester gas. Though the application was on a turbine, the important point with this memorandum is the catalyst manufacturers concern over detrimental effects on their catalysts due to contaminants in the digester gas.

Based upon AMSA member agency experience with catalysts, the fact that there are no catalyst controlled digester gas or landfill gas engines successfully operating in the United States, and that pretreatment systems to remove Siloxane are costly to install and maintain; the ICCR Coordinating Committee does not believe that catalytic control has proven reliable or cost-effective enough to be considered for above-the-floor MACT controls.

Air Injection for Rich-Burn Engines

There are ten (10) rich-burn, landfill gas fired engines utilizing an air injection emission control technology. These ten engines were originally equipped with NSCR to control NO_X emissions. After early failure of the NSCR devices due to catalyst fouling, the operator attempted to meet emission requirements by modifying the operating parameters of the engines. This included running the engine at fuel-rich conditions. This resulted in lower NO_X emissions, however, Carbon Monoxide (CO) emissions increased. Air injection into the exhaust stream was then added to control CO emissions.

The facility operator has received several notices of violation between January 1, 1990 and May 21, 1998 for the control systems. At one plant, seven NO_X and two CO emission violations were received. At the second plant, five NO_X and two CO emission violations were received. It is important to note that the facility operator has decided to replace these ten rich-burn engines with lean-burn engines.

Although the plants do not have actual emission data, there are several theoretical problems with this emission control system. Rich-burn engines operating fuel-rich produce more CO and formaldehyde emissions than engines operating at proper air-to-fuel ratios. The injection of air must be done precisely; if either too much or too little air is injected, both the rate of exhaust gas combustion and the resulting CO reduction efficiency will be affected. Proper mixing of the injected air is also important, since poor air distribution can cause sections of the exhaust gas stream to remain unburned.

Even if the control system is working perfectly, there is no evidence that it will reduce HAP emissions beyond that of a properly tuned engine. Therefore, the ICCR Coordinating Committee has determined that the use of fuel-rich/air injection for HAP emission control on rich-burn internal combustion engines is not appropriate.

Landfill Gas Flare-Afterburner

There is a landfill operating in Orange County (Prima Deschecha) that has installed a lean burn engine coupled with a flare-afterburner to meet the landfill gas, 98% destruction efficiency requirement of NSPS Subpart WWW. In addition, the Tajiguas landfill in Santa Barbara County has been issued a permit-to-construct (PTC) by the APCD to install a similar lean burn engine/flare-afterburner system. Based upon the PTC the flare-afterburner will operate in two modes. Its primary mode will be to treat the exhaust gas from the lean burn engine and directly burn a portion of the fugitive landfill gas that is collected and cannot be burned in the engine. The secondary mode of operation is to burn all of the fugitive landfill gas collected when the engine is not operating.

The NSPS Subpart WWW requires the control of Non-Methane Organic Compounds (NMOC). There is no requirement for HAP control. A NO_X and Reactive Organic Compound (ROC) Best Available Control Technology (BACT) control cost effectiveness analysis was conducted for the Tajigues landfill PTC. This may have also been done for the Prima Deschecha landfill project. The economic analysis showed the project to be cost-effective for both NO_X ($59/ton removed) and ROC ($1,589/ton removed) control. In the PTC's BACT cost-effectiveness analysis, the $1,589/ton of ROC removed is based on 25 tons/yr of ROC produced by the engine. The important consideration is that the economic evaluation may be different if it was based upon HAP destruction since a new lean burn engine of this size (4,314 bhp) burning landfill gas would likely emit substantially less than 25 tons/yr of formaldehyde.

Since the afterburner-flare operates at a temperature in excess of 1500 ^oF, there is the potential that this technology may reduce HAP emissions. In addition, these systems are being installed to comply with NSPS Subpart WWW. Therefore, the ICCR Coordinating Committee believes that EPA should further investigate this technology for the control of landfill gas engines.

<u>Conclusion</u>

In summary, the ICCR Coordinating Committee does not believe that catalytic controls or air injection for rich-burn engines have proven reliable or cost-effective enough to be considered for above-the-floor MACT controls. The ICCR Coordinating Committee recommends that EPA further investigate the HAP reduction performance and cost-effectiveness of the lean burn engine/flare-afterburner control system for landfill gas fired engines that is installed at the Prima Deschecha landfill in Orange County, California and soon to be installed at the Tajigues landfill in Santa Barbara County, California.

Supporting Documentation

1. Malcolm Pirnie Consultants; Technical Memorandum, Catalyst Performance Investigation; prepared for the Nassau County Department of Public Works; September 1996

2. City of Los Angeles, Department of Public Works, Bureau of Engineering; Technical Report, CO and NO_X Mitigation Catalyst Testing and Evaluation; December 1993

3. Los Angeles County Sanitation District; Catalytic Denitrification of Exhaust from Reciprocating Engines Fueled with Sewage Digester Gas; 77th Annual Meeting of the Air Pollution Control Association; June 1984

4. Los Angeles County Sanitation District; Memorandum; Responses to RFP for Correcting TEF/SCR System; July 1996